SECTION 2

SPCC REGULATION

Complete Regulation with Citation-Specific Guidance

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SPCC REGULATION – 40 CFR 112 OF 17 JUL 2002

Preface.

The following section lists 40 CFR 112 of 17 July 2002 in its entirety. This guidance has been tailored to assist Navy and Marine Corps installations in the interpretation and implementation of SPCC requirements, and in the preparation of installation SPCC Plans.

This document is designed to be used along with the Spill Prevention Guidance Document (NFESC, 1998, User's Guide UG-2033-ENV), accessible on the internet at [http://enviro.nfesc.navy.mil/ps/spillprev]. Although written prior to the 17 Jul 2002 SPCC rule (e.g., not every citation will match up with the new regulation), it is far from obsolete; sections of that document containing valuable SPCC related information are frequently referenced in guidance sections below. But unlike this document, which is designed primarily to systematically provide guidance, interpretation, and pertinent information on the specific, sequential requirements of 40 CFR 112, the 1998 Spill Prevention Guidance Document instead adopts a more topical, text-book approach in presenting information on facilities, devices, controls, practices, planning, etc.

Following each section of the regulation, guidance on implementation of the requirements set forth in that section has been inserted. Guidance sections can be easily distinguished from text belonging to the regulation by **bold** font located between sets of double lines [═══]. Each guidance section begins with the symbol [♦] and a citation with a heading that describes the information the citation covers (these headings may be directly referenced from the Section Table of Contents listed on the preceding pages). The **bolded** guidance is to be used with the corresponding section of regulation, not in lieu of the regulation. The guidance sections do not discuss every nuance set forth by the regulation, but rather focus on ambiguous or potentially confusing requirements where interpretation and recommendations may be most helpful for Navy and Marine Corps installations implementing SPCC Plans.

An SPCC Plan must be certified by a Professional Engineer (PE), whose endorsement indicates the Plan not only meets regulatory requirements, but is also adequate for the facility and has been prepared in accordance with applicable industry standards. Therefore, when following the recommendations contained in this document, it should be understood that that the minimum requirements described herein may not be adequate for each facility. Rather, good engineering judgement must be exercised by the certifying PE.

Note that in various responses to inquiries, the EPA has indicated because of the technical nature of amendments (i.e., the new requirements) to 40 CFR 112, a PE needs to review all existing SPCC Plans before 17 August 2004; certify that the Plan is adequate for the facility; certify that technical standards have been considered; certify that inspections and tests are adequate for the facility; and certify that the Plan has been prepared in accordance with good engineering practice, including consideration of applicable industry standards.

The new rule published 17 July 2002 gives considerable latitude to the EPA Regional Administrator to carry out the intent of Part 112. Questions or clarification on interpretations regarding specific or unusual circumstances should be directed to that office.

In some guidance sections, additional cost information has been included to further assist installations in meeting the SPCC requirements. This information has been included to provide a 'starting point' from which installations may identify and begin to understand the relative costs of various options to improve their compliance stature. The illustrative cost estimates are rough approximations that could reasonably be expected to vary with respect to size, scope, vendor, location, mobilization, economy of scale, region, etc., sometimes quite significantly. Actual costs should be investigated prior to construction, equipment

purchase, budget submissions, or committing resources to a project.

Refer to Section 3 Tabs A – E for guidance on SPCC requirements, arranged by topic (i.e., bulk storage containers, loading/unloading racks, valves and piping, electrical and other operating equipment, and security).

PART 112 – OIL POLLUTION PREVENTION

1. The authority for part 112 continues to read as follows:
   Authority: 33 U.S.C. 1251 *et seq*.; 33 U.S.C 2720; E.O. 12777 (October 18, 1991), 3 CFR, 1991 Comp., p. 351.

2. Part 112 is amended by designating §§ 112.1 through 112.7 as subpart A, adding a subpart heading and revising newly designated subpart A to read as follows:

Subpart A – Applicability, Definitions, and General Requirements For All Facilities and All Types of Oils

Sec.
112.1 General applicability.
112.2 Definitions.
112.3 Requirement to prepare and implement a Spill Prevention, Control, and Countermeasure Plan.
112.4 Amendment of Spill Prevention, Control, and Countermeasure Plan by Regional Administrator.
112.5 Amendment of Spill Prevention, Control, and Countermeasure Plan by owners or operators.
112.6 [Reserved].
112.7 General requirements for Spill Prevention, Control, and Countermeasure Plans.

Subpart A – Applicability, Definitions, and General Requirements for All Facilities and All Types of Oils

§ 112.1 General applicability.

(a)

(1) This part establishes procedures, methods, equipment, and other requirements to prevent the discharge of oil from non-transportation-related onshore and offshore facilities into or upon the navigable waters of the United States or adjoining shorelines, or into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or that may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson Fishery Conservation and Management Act).

(2) As used in this part, words in the singular also include the plural and words in the masculine gender also include the feminine and vice versa, as the case may require.

(b) Except as provided in paragraph (d) of this section, this part applies to any owner or operator of a non-transportation-related onshore or offshore facility engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, which due to its location, could reasonably be expected to discharge oil in quantities that may be harmful, as described in part 110 of this chapter, into or upon the navigable waters of the United States or adjoining shorelines, or into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or that may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson Fishery Conservation and Management Act) that has oil in:

(1) Any aboveground container;

(2) Any completely buried tank as defined in § 112.2;

(3) Any container that is used for standby storage, for seasonal storage, or for temporary storage, or not otherwise "permanently closed" as defined in § 112.2;

(4) Any "bunkered tank" or "partially buried tank" as defined in § 112.2, or any container in a vault, each of which is considered an aboveground storage container for purposes of this part.

(c) As provided in section 313 of the Clean Water Act (CWA), departments, agencies, and instrumentalities of the Federal government are subject to this part to the same extent as any person.

(d) Except as provided in paragraph (f) of this section, this part does not apply to:

(1) The owner or operator of any facility, equipment, or operation that is not subject to the jurisdiction of the Environmental Protection Agency (EPA) under section 311(j)(1)(C) of the CWA, as follows:

(i) Any onshore or offshore facility, that due to its location, could not reasonably be expected to have a discharge as described in paragraph (b) of this section. This determination must be based solely upon consideration of the geographical and location aspects of the facility (such as proximity to navigable waters or adjoining shorelines, land contour, drainage, etc.) and must exclude consideration of manmade features such as dikes, equipment or other structures, which may serve to restrain, hinder, contain, or otherwise prevent a discharge as described in paragraph (b) of this section.

(ii) Any equipment, or operation of a vessel or transportation-related onshore or offshore facility which is subject to the authority and control of the U.S. Department of Transportation, as defined in the Memorandum of Understanding between the Secretary of Transportation and the Administrator of EPA, dated November 24, 1971 (Appendix A of this part).

(iii) Any equipment, or operation of a vessel or onshore or offshore facility which is subject to the authority and control of the U.S. Department of Transportation or the U.S. Department of the Interior, as defined in the Memorandum of Understanding between the Secretary of Transportation, the Secretary of the Interior, and the Administrator of EPA, dated November 8, 1993 (Appendix B of this part).

(2) Any facility which, although otherwise subject to the jurisdiction of EPA, meets both of the following requirements:

(i) The completely buried storage capacity of the facility is 42,000 gallons or less of oil. For purposes of this exemption, the completely buried storage capacity of a facility excludes the capacity of a completely buried tank, as defined in § 112.2, and connected underground piping, underground ancillary equipment, and containment systems, that is currently subject to all of the technical requirements of part 280 of this chapter or all of the technical requirements of a State program approved under part 281 of this chapter. The completely buried storage capacity of a facility also excludes the capacity of a container that is "permanently closed," as defined in § 112.2.

(ii) The aggregate aboveground storage capacity of the facility is 1,320 gallons or less of oil. For purposes of this exemption, only containers of oil with a capacity of 55 gallons or greater are counted. The aggregate aboveground storage capacity of a facility excludes the capacity of a container that is "permanently closed", as defined in § 112.2.

(3) Any offshore oil drilling, production, or workover facility that is subject to the notices and regulations of the Minerals Management Service, as specified in the Memorandum of Understanding between the Secretary of Transportation, the Secretary of the Interior, and the Administrator of EPA, dated November 8, 1993 (Appendix B of this part).

(4) Any completely buried storage tank, as defined in § 112.2, and connected underground piping, underground ancillary equipment, and containment systems, at any facility, that is subject to all of the technical requirements of part 280 of this chapter or a State program approved under part 281 of this chapter, except that such a tank must be marked on the facility diagram as provided in § 112.7(a)(3), if the facility is otherwise subject to this part.

(5) Any container with a storage capacity of less than 55 gallons of oil.

(6) Any facility or part thereof used exclusively for wastewater treatment and not used to satisfy any requirement of this part. The production, recovery, or recycling of oil is not wastewater treatment for purposes of this paragraph.

(e) This part establishes requirements for the preparation and implementation of Spill Prevention, Control, and Countermeasure (SPCC) Plans. SPCC Plans are designed to complement existing laws, regulations, rules, standards, policies, and procedures pertaining to safety standards, fire prevention, and pollution prevention rules. The purpose of an SPCC Plan is to form a comprehensive Federal/State spill prevention program that minimizes the potential for discharges. The SPCC Plan must address all relevant spill prevention, control, and countermeasures necessary at the specific facility. Compliance with this part does not in any way relieve the owner or operator of an onshore or an offshore facility from compliance with other Federal, State, or local laws.

(f) Notwithstanding paragraph (d) of this section, the Regional Administrator may require that the owner or operator of any facility subject to the jurisdiction of EPA under section 311(j) of the CWA prepare and implement an SPCC Plan, or any applicable part, to carry out the purposes of the CWA.

(1) Following a preliminary determination, the Regional Administrator must provide a written notice to the owner or operator stating the reasons why he must prepare an SPCC Plan, or applicable part. The Regional Administrator must send such notice to the owner or operator by certified mail or by personal delivery. If the owner or operator is a corporation, the Regional Administrator must also mail a copy of such notice to the registered agent, if any and if known, of the corporation in the State where the facility is located.

(2) Within 30 days of receipt of such written notice, the owner or operator may provide information and data and may consult with the Agency about the need to prepare an SPCC Plan, or applicable part.

(3) Within 30 days following the time under paragraph (b)(2) of this section within which the owner or operator may provide information and data and consult with the Agency about the need to prepare an SPCC Plan, or applicable part, the Regional Administrator must make a final determination regarding whether the owner or operator is required to prepare and implement an SPCC Plan, or applicable part. The Regional Administrator must send the final determination to the owner or operator by certified mail or by personal delivery. If the owner or operator is a corporation, the Regional Administrator must also mail a copy of the final determination to the registered agent, if any and if known, of the corporation in the State where the facility is located.

(4) If the Regional Administrator makes a final determination that an SPCC Plan, or applicable part, is necessary, the owner or operator must prepare the Plan, or applicable part, within six months of that final determination and implement the Plan, or applicable part, as soon as

possible, but not later than one year after the Regional Administrator has made a final determination.

(5) The owner or operator may appeal a final determination made by the Regional Administrator requiring preparation and implementation of an SPCC Plan, or applicable part, under this paragraph. The owner or operator must make the appeal to the Administrator of EPA within 30 days of receipt of the final determination under paragraph (b)(3) of this section from the Regional Administrator requiring preparation and/or implementation of an SPCC Plan, or applicable part. The owner or operator must send a complete copy of the appeal to the Regional Administrator at the time he makes the appeal to the Administrator. The appeal must contain a clear and concise statement of the issues and points of fact in the case. In the appeal, the owner or operator may also provide additional information. The additional information may be from any person. The Administrator may request additional information from the owner or operator. The Administrator must render a decision within 60 days of receiving the appeal or additional information submitted by the owner or operator and must serve the owner or operator with the decision made in the appeal in the manner described in paragraph (f)(1) of this section.

♦ § 112.1 ~ General Applicability ♦

§ 112.1 describes how your installation may be subject to Part 112. Navy and Marine Corps installations that meet either of the following criteria are subject to 40 CFR 112 (providing the installation stores, transfers, distributes, or consumes oil and oil products that could reasonably be expected to reach navigable waters if spilled or released) and must prepare an SPCC Plan:

- **The installation's underground oil storage capacity exceeds 42,000 gal (excluding completely buried storage tanks subject to all of the technical requirements of 40 CFR 280).**
- **The installation's aggregate aboveground oil storage capacity (including all tanks, containers, and operating equipment 55 gal or greater in capacity) exceeds 1,320 gal.**

An installation where either of the above scenarios applies is subject to 40 CFR 112 and must prepare an SPCC Plan.

In determining whether your installation is subject to Part 112, the total storage capacity must be tabulated, not the amount of oil actually stored. Note that an installation may be subject to Part 112 even if the oil storage capacity is comprised only of 55 gal containers or operating equipment (e.g., transformers) in excess of 55 gal, providing the 1,320 gal aggregate aboveground oil storage capacity threshold is exceeded. Note also that permanently closed tanks (as defined in § 112.2) are not included in the calculation of total storage capacity.

In determining whether a spill or release at your installation could reasonably be expected to reach navigable waters, consideration must solely be based upon the geographical and location aspects of the facility (such as proximity to navigable waters or adjoining shorelines, land contour, drainage, etc.) and must exclude consideration of manmade features such as dikes, equipment, or other structures that might restrain, contain, or otherwise prevent a discharge from occurring.

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§ 112.2 Definitions.

For the purposes of this part:

Adverse weather means weather conditions that make it difficult for response equipment and personnel to clean up or remove spilled oil, and that must be considered when identifying response systems and equipment in a response plan for the applicable operating environment.

Factors to consider include significant wave height as specified in Appendix E to this part (as appropriate), ice conditions, temperatures, weather-related visibility, and currents within the area in which the systems or equipment is intended to function.

Alteration means any work on a container involving cutting, burning, welding, or heating operations that changes the physical dimensions or configuration of the container.

Animal fat means a non-petroleum oil, fat, or grease of animal, fish, or marine mammal origin.

Breakout tank means a container used to relieve surges in an oil pipeline system or to receive and store oil transported by a pipeline for reinjection and continued transportation by pipeline.

Bulk storage container means any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container.

Bunkered tank means a container constructed or placed in the ground by cutting the earth and re-covering the container in a manner that breaks the surrounding natural grade, or that lies above grade, and is covered with earth, sand, gravel, asphalt, or other material. A bunkered tank is considered an aboveground storage container for purposes of this part.

Completely buried tank means any container completely below grade and covered with earth, sand, gravel, asphalt, or other material. Containers in vaults, bunkered tanks, or partially buried tanks are considered aboveground storage containers for purposes of this part.

Complex means a facility possessing a combination of transportation-related and non-transportation-related components that is subject to the jurisdiction of more than one Federal agency under section 311(j) of the CWA.

Contiguous zone means the zone established by the United States under Article 24 of the Convention of the Territorial Sea and Contiguous Zone, that is contiguous to the territorial sea and that extends nine miles seaward from the outer limit of the territorial area.

Contract or other approved means means:

(1) A written contractual agreement with an oil spill removal organization that identifies and ensures the availability of the necessary personnel and equipment within appropriate response times; and/or

(2) A written certification by the owner or operator that the necessary personnel and equipment resources, owned or operated by the facility owner or operator, are available to respond to a discharge within appropriate response times; and/or

(3) Active membership in a local or regional oil spill removal organization that has identified and ensures adequate access through such membership to necessary personnel and equipment to respond to a discharge within appropriate response times in the specified geographic area; and/or

(4) Any other specific arrangement approved by the Regional Administrator upon request of the owner or operator.

Discharge includes, but is not limited to, any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of oil, but excludes discharges in compliance with a permit under section 402 of the CWA; discharges resulting from circumstances identified, reviewed, and made a part of the public record with respect to a permit issued or modified under section 402 of the CWA, and subject to a

condition in such permit; or continuous or anticipated intermittent discharges from a point source, identified in a permit or permit application under section 402 of the CWA, that are caused by events occurring within the scope of relevant operating or treatment systems. For purposes of this part, the term discharge shall not include any discharge of oil that is authorized by a permit issued under section 13 of the River and Harbor Act of 1899 (33 U.S.C. 407).

Facility means any mobile or fixed, onshore or offshore building, structure, installation, equipment, pipe, or pipeline (other than a vessel or a public vessel) used in oil well drilling operations, oil production, oil refining, oil storage, oil gathering, oil processing, oil transfer, oil distribution, and waste treatment, or in which oil is used, as described in Appendix A to this part. The boundaries of a facility depend on several site-specific factors, including, but not limited to, the ownership or operation of buildings, structures, and equipment on the same site and the types of activity at the site.

Fish and wildlife and sensitive environments means areas that may be identified by their legal designation or by evaluations of Area Committees (for planning) or members of the Federal On-Scene Coordinator's spill response structure (during responses). These areas may include wetlands, National and State parks, critical habitats for endangered or threatened species, wilderness and natural resource areas, marine sanctuaries and estuarine reserves, conservation areas, preserves, wildlife areas, wildlife refuges, wild and scenic rivers, recreational areas, national forests, Federal and State lands that are research national areas, heritage program areas, land trust areas, and historical and archaeological sites and parks. These areas may also include unique habitats such as aquaculture sites and agricultural surface water intakes, bird nesting areas, critical biological resource areas, designated migratory routes, and designated seasonal habitats.

Injury means a measurable adverse change, either long- or short-term, in the chemical or physical quality or the viability of a natural resource resulting either directly or indirectly from exposure to a discharge, or exposure to a product of reactions resulting from a discharge.

Maximum extent practicable means within the limitations used to determine oil spill planning resources and response times for on-water recovery, shoreline protection, and cleanup for worst case discharges from onshore non-transportation-related facilities in adverse weather. It includes the planned capability to respond to a worst case discharge in adverse weather, as contained in a response plan that meets the requirements in § 112.20 or in a specific plan approved by the Regional Administrator.

Navigable waters means the waters of the United States, including the territorial seas.

(1) The term includes:

(i) All waters that are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters subject to the ebb and flow of the tide;

(ii) All interstate waters, including interstate wetlands;

(iii) All other waters such as intrastate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, wetlands, sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds, the use, degradation, or destruction of which could affect interstate or foreign commerce including any such waters:

(A) That are or could be used by interstate or foreign travelers for recreational or other purposes; or

(B) From which fish or shellfish are or could be taken and sold in interstate or foreign commerce; or,

(C) That are or could be used for industrial purposes by industries in interstate commerce;

(iv) All impoundments of waters otherwise defined as waters of the United States under this section;

(v) Tributaries of waters identified in paragraphs (1)(i) through (iv) of this definition;

(vi) The territorial sea; and

(vii) Wetlands adjacent to waters (other than waters that are themselves wetlands) identified in paragraph (1) of this definition.

(2) Waste treatment systems, including treatment ponds or lagoons designed to meet the requirements of the CWA (other than cooling ponds which also meet the criteria of this definition) are not waters of the United States. Navigable waters do not include prior converted cropland. Notwithstanding the determination of an area's status as prior converted cropland by any other Federal agency, for the purposes of the CWA, the final authority regarding CWA jurisdiction remains with EPA.

Non-petroleum oil means oil of any kind that is not petroleum-based, including but not limited to: Fats, oils, and greases of animal, fish, or marine mammal origin; and vegetable oils, including oils from seeds, nuts, fruits, and kernels.

Offshore facility means any facility of any kind (other than a vessel or public vessel) located in, on, or under any of the navigable waters of the United States, and any facility of any kind that is subject to the jurisdiction of the United States and is located in, on, or under any other waters.

Oil means oil of any kind or in any form, including, but not limited to: fats, oils, or greases of animal, fish, or marine mammal origin; vegetable oils, including oils from seeds, nuts, fruits, or kernels; and, other oils and greases, including petroleum, fuel oil, sludge, synthetic oils, mineral oils, oil refuse, or oil mixed with wastes other than dredged spoil.

Oil Spill Removal Organization means an entity that provides oil spill response resources, and includes any for-profit or not-for-profit contractor, cooperative, or in-house response resources that have been established in a geographic area to provide required response resources.

Onshore facility means any facility of any kind located in, on, or under any land within the United States, other than submerged lands.

Owner or operator means any person owning or operating an onshore facility or an offshore facility, and in the case of any abandoned offshore facility, the person who owned or operated or maintained the facility immediately prior to such abandonment.

Partially buried tank means a storage container that is partially inserted or constructed in the ground, but not entirely below grade, and not completely covered with earth, sand, gravel, asphalt, or other material. A partially buried tank is considered an aboveground storage container for purposes of this part.

Permanently closed means any container or facility for which:

(1) All liquid and sludge has been removed from each container and connecting line; and

(2) All connecting lines and piping have been disconnected from the container and blanked off, all valves (except for ventilation valves) have been closed and locked, and conspicuous signs have been posted on each container stating that it is a permanently closed container and

noting the date of closure.

Person includes an individual, firm, corporation, association, or partnership.

Petroleum oil means petroleum in any form, including but not limited to crude oil, fuel oil, mineral oil, sludge, oil refuse, and refined products.

Production facility means all structures (including but not limited to wells, platforms, or storage facilities), piping (including but not limited to flowlines or gathering lines), or equipment (including but not limited to workover equipment, separation equipment, or auxiliary non-transportation-related equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of oil, or associated storage or measurement, and located in a single geographical oil or gas field operated by a single operator.

Regional Administrator means the Regional Administrator of the Environmental Protection Agency, in and for the Region in which the facility is located.

Repair means any work necessary to maintain or restore a container to a condition suitable for safe operation, other than that necessary for ordinary, day-to-day maintenance to maintain the functional integrity of the container and that does not weaken the container.

Spill Prevention, Control, and Countermeasure Plan; SPCC Plan, or Plan means the document required by § 112.3 that details the equipment, workforce, procedures, and steps to prevent, control, and provide adequate countermeasures to a discharge.

Storage capacity of a container means the shell capacity of the container.

Transportation-related and non-transportation-related, as applied to an onshore or offshore facility, are defined in the Memorandum of Understanding between the Secretary of Transportation and the Administrator of the Environmental Protection Agency, dated November 24, 1971, (Appendix A of this part).

United States means the States, the District of Columbia, the Commonwealth of Puerto Rico, the Commonwealth of the Northern Mariana Islands, Guam, American Samoa, the U.S. Virgin Islands, and the Pacific Island Governments.

Vegetable oil means a non-petroleum oil or fat of vegetable origin, including but not limited to oils and fats derived from plant seeds, nuts, fruits, and kernels.

Vessel means every description of watercraft or other artificial contrivance used, or capable of being used, as a means of transportation on water, other than a public vessel.

Wetlands means those areas that are inundated or saturated by surface or groundwater at a frequency or duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include playa lakes, swamps, marshes, bogs, and similar areas such as sloughs, prairie potholes, wet meadows, prairie river overflows, mudflats, and natural ponds.

Worst case discharge for an onshore non-transportation-related facility means the largest foreseeable discharge in adverse weather conditions as determined using the worksheets in Appendix D to this part.

♦ § 112.2 ~ Definitions ♦

§ 112.2 provides detailed definitions to terms used throughout Part 112.

As noted above, a 'facility' can refer to any building, structure, or piece of equipment in which oil is used. A facility can be as small as a single container, or as large as the entire Navy or Marine Corps installation. EPA guidance on the specific factors to be used in determining the extent of a facility include the ownership or operation of those buildings, structures, or pieces of equipment, or the type of activities being carried on at the facility. Ultimately, the PE and the owner or operator must decide upon the extent of the facility.

Most Navy and Marine Corps installations incorporate a majority of the oil storage areas or locations on Base into the installation SPCC Plan. Occasionally, installations choose to define large or uniquely individual tenants as separate facilities, and request they maintain their own separate SPCC Plans. Examples of scenarios where this approach may be utilized include installations with tenants such as Naval Aviation Depots (NADEP), utility companies, government-owned contractor-operated activities, etc.

It is also possible to define a segment of an installation as a separate facility that is not subject to Part 112, and therefore does not require its own separate SPCC Plan. For example, home heating oil tanks at military housing units may individually or collectively be defined as separate facilities. If the cumulative capacity of the aboveground home heating oil tank(s) (55 gal or greater) does not exceed 1,320 gal, and the cumulative capacity of the underground home heating oil tank(s) (55 gal or greater) does not exceed 42,000 gal, the facility would not be subject to Part 112. Alternately, if either the 1,320 gal or the 42,000 gal thresholds are exceeded, the tank(s) (55 gal or greater) must be included in an SPCC Plan developed for this facility (or be simply incorporated into the installation SPCC Plan). Interpretation uncertainties that may arise when splitting an installation into several separate facilities should be coordinated through the EPA Regional Administrator.

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§ 112.3 Requirement to prepare and implement a Spill Prevention, Control, and Countermeasure Plan.

The owner or operator of an onshore or offshore facility subject to this section must prepare a Spill Prevention, Control, and Countermeasure Plan (hereafter "SPCC Plan" or "Plan"), in writing, and in accordance with § 112.7, and any other applicable section of this part.

(a) If your onshore or offshore facility was in operation on or before August 16, 2002, you must maintain your Plan, but must amend it, if necessary to ensure compliance with this part, on or before February 17, 2003, and must implement the amended Plan as soon as possible, but not later than August 18, 2003. If your onshore or offshore facility becomes operational after August 16, 2002, through August 18, 2003, and could reasonably be expected to have a discharge as described in § 112.1(b), you must prepare a Plan on or before August 18, 2003, and fully implement it as soon as possible, but not later than August 18, 2003.

(b) If you are the owner or operator of an onshore or offshore facility that becomes operational after August 18, 2003, and could reasonably be expected to have a discharge as described in § 112.1(b), you must prepare and implement a Plan before you begin operations.

(c) If you are the owner or operator of an onshore or offshore mobile facility, such as an onshore drilling or workover rig, barge mounted offshore drilling or workover rig, or portable fueling facility, you must prepare, implement, and maintain a facility Plan as required by this section. This provision does not require that you prepare a new Plan each time you move the facility to a new site. The Plan may be a general plan. When you move the mobile or portable facility, you must locate and install it using the discharge prevention practices outlined in the Plan for the facility. You may not operate a mobile or portable facility subject to this part unless you have implemented the Plan. The Plan is applicable only while the facility is in a fixed (non-transportation) operating mode.

(d) A licensed Professional Engineer must review and certify a Plan for it to be effective to satisfy the

requirements of this part.

(1) By means of this certification the Professional Engineer attests:

(i) That he is familiar with the requirements of this part;

(ii) That he or his agent has visited and examined the facility;

(iii) That the Plan has been prepared in accordance with good engineering practice, including consideration of applicable industry standards, and with the requirements of this part;

(iv) That procedures for required inspections and testing have been established; and

(v) That the Plan is adequate for the facility.

(2) Such certification shall in no way relieve the owner or operator of a facility of his duty to prepare and fully implement such Plan in accordance with the requirements of this part.

(e) If you are the owner or operator of a facility for which a Plan is required under this section, you must:

(1) Maintain a complete copy of the Plan at the facility if the facility is normally attended at least four hours per day, or at the nearest field office if the facility is not so attended, and

(2) Have the Plan available to the Regional Administrator for on-site review during normal working hours.

(f) *Extension of time*.

(1) The Regional Administrator may authorize an extension of time for the preparation and full implementation of a Plan, or any amendment thereto, beyond the time permitted for the preparation, implementation, or amendment of a Plan under this part, when he finds that the owner or operator of a facility subject to this section, cannot fully comply with the requirements as a result of either nonavailability of qualified personnel, or delays in construction or equipment delivery beyond the control and without the fault of such owner or operator or his agents or employees.

(2) If you are an owner or operator seeking an extension of time under paragraph (f)(1) of this section, you may submit a written extension request to the Regional Administrator. Your request must include:

(i) A full explanation of the cause for any such delay and the specific aspects of the Plan affected by the delay;

(ii) A full discussion of actions being taken or contemplated to minimize or mitigate such delay; and

(iii) A proposed time schedule for the implementation of any corrective actions being taken or contemplated, including interim dates for completion of tests or studies, installation and operation of any necessary equipment, or other preventive measures. In addition you may present additional oral or written statements in support of your extension request.

(3) The submission of a written extension request under paragraph (f)(2) of this section does not relieve you of your obligation to comply with the requirements of this part. The Regional Administrator may request a copy of your Plan to evaluate the extension request. When the Regional Administrator authorizes an extension of time for particular equipment or other

specific aspects of the Plan, such extension does not affect your obligation to comply with the requirements related to other equipment or other specific aspects of the Plan for which the Regional Administrator has not expressly authorized an extension.

♦ § 112.3 ~ Requirement to Prepare and Implement a Spill Prevention, Control, and Countermeasure Plan ♦

§ 112.3 stipulates that an installation subject to Part 112 must prepare an SPCC Plan, in accordance with § 112.7. A licensed PE must review and certify the SPCC Plan is adequate for the facility. The certifying PE must ensure the SPCC Plan:

- **Includes specific criteria and schedules for inspections and integrity testing.**
- **Provides citations from industry standards pertaining to containers, inspections, tests, and other requirements.**
- **Addresses concern for brittle fracture and other catastrophic failure modes of oil containers.**

The PE is responsible for certifying that the SPCC Plan is adequate and meets all regulatory requirements, including enumeration of all tests that have been completed, plus those that should be completed before the facility commences operations, and those that should be undertaken periodically after it commences operations. The PE may include in the SPCC Plan a schedule for testing, with specific time frames for the completion of that testing. SPCC Plans do not need to be submitted to the EPA for approval, but must be available for inspection by the EPA. Note that the PE certification also attests to the fact that the PE or an agent of the PE has visited and examined the facility, and that the Plan has been prepared in accordance with applicable industry standards.

The 17 July 2002 version of Part 112 required SPCC Plans be amended or updated, if necessary, to conform to the new requirements by 17 February 2003, and be fully implemented by 18 August 2003. An amendment to Part 112 promulgated on 17 April 2003, however, superceded those deadlines; it requires SPCC Plans be amended or updated, if necessary, to conform to the new requirements by 17 August 2004, and be fully implemented by 18 February 2005.

In various responses to inquiries, the EPA has indicated because of the technical nature of amendments (i.e., the new requirements) to 40 CFR 112, a PE needs to review all existing SPCC Plans before 17 August 2004; certify that the Plan is adequate for the facility; certify that technical standards have been considered; certify that inspections and tests are adequate for the facility; and certify that the Plan has been prepared in accordance with good engineering practice, including consideration of applicable industry standards.

Cost Information
Information on SPCC Plan preparation is included in Section 4 Appendix A:

- **SPCC Plan Preparation: $5,000 - $10,000 for very small activities (1 - 5 tanks), $15,000 - $25,000 for small activities (5 - 20 tanks), $25,000 - $50,000 for medium activities (20 - 50 tanks), $50,000 - $75,000 for large activities (> 50 tanks) (per Navy Environmental Requirements Guidebook).**

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§ 112.4 Amendment of Spill Prevention, Control, and Countermeasure Plan by Regional Administrator.

If you are the owner or operator of a facility subject to this part, you must:

(a) Notwithstanding compliance with § 112.3, whenever your facility has discharged more than 1,000 U.S. gallons of oil in a single discharge as described in § 112.1(b), or discharged more than 42

U.S. gallons of oil in each of two discharges as described in § 112.1(b), occurring within any twelve month period, submit the following information to the Regional Administrator within 60 days from the time the facility becomes subject to this section:

(1) Name of the facility;

(2) Your name;

(3) Location of the facility;

(4) Maximum storage or handling capacity of the facility and normal daily throughput;

(5) Corrective action and countermeasures you have taken, including a description of equipment repairs and replacements;

(6) An adequate description of the facility, including maps, flow diagrams, and topographical maps, as necessary;

(7) The cause of such discharge as described in § 112.1(b), including a failure analysis of the system or subsystem in which the failure occurred;

(8) Additional preventive measures you have taken or contemplated to minimize the possibility of recurrence; and

(9) Such other information as the Regional Administrator may reasonably require pertinent to the Plan or discharge.

(b) Take no action under this section until it applies to your facility. This section does not apply until the expiration of the time permitted for the initial preparation and implementation of the Plan under § 112.3, but not including any amendments to the Plan.

(c) Send to the appropriate agency or agencies in charge of oil pollution control activities in the State in which the facility is located a complete copy of all information you provided to the Regional Administrator under paragraph (a) of this section. Upon receipt of the information such State agency or agencies may conduct a review and make recommendations to the Regional Administrator as to further procedures, methods, equipment, and other requirements necessary to prevent and to contain discharges from your facility.

(d) Amend your Plan, if after review by the Regional Administrator of the information you submit under paragraph (a) of this section, or submission of information to EPA by the State agency under paragraph (c) of this section, or after on-site review of your Plan, the Regional Administrator requires that you do so. The Regional Administrator may require you to amend your Plan if he finds that it does not meet the requirements of this part or that amendment is necessary to prevent and contain discharges from your facility.

(e) Act in accordance with this paragraph when the Regional Administrator proposes by certified mail or by personal delivery that you amend your SPCC Plan. If the owner or operator is a corporation, he must also notify by mail the registered agent of such corporation, if any and if known, in the State in which the facility is located. The Regional Administrator must specify the terms of such proposed amendment. Within 30 days from receipt of such notice, you may submit written information, views, and arguments on the proposed amendment. After considering all relevant material presented, the Regional Administrator must either notify you of any amendment required or rescind the notice. You must amend your Plan as required within 30 days after such notice, unless the Regional Administrator, for good cause, specifies another effective date. You must implement the amended Plan as soon as possible, but not later than six months after you amend your Plan, unless the Regional Administrator specifies another date.

(f) If you appeal a decision made by the Regional Administrator requiring an amendment to an SPCC Plan, send the appeal to the EPA Administrator in writing within 30 days of receipt of the notice from the Regional Administrator requiring the amendment under paragraph (e) of this section. You must send a complete copy of the appeal to the Regional Administrator at the time you make the appeal. The appeal must contain a clear and concise statement of the issues and points of fact in the case. It may also contain additional information from you, or from any other person. The EPA Administrator may request additional information from you, or from any other person. The EPA Administrator must render a decision within 60 days of receiving the appeal and must notify you of his decision.

♦ § 112.4 ~ Amendment of Spill Prevention, Control, and Countermeasure Plan by Regional Administrator ♦

§ 112.4 applies only if the installation has discharged more than 1,000 gal of oil in a single event, or more than 42 gal of oil in each of two events in any twelve month period. When either of these events has occurred, a report must be submitted to the EPA Regional Administrator and any State or local agencies in charge of oil pollution control activities.

Scrutiny of the information submitted may result in recommended improvements (e.g., procedures, methods, equipment, etc.) designed to prevent and contain any future discharges from the installation. The EPA Regional Administrator may also require an amendment of the SPCC Plan.

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§ 112.5 Amendment of Spill Prevention, Control, and Countermeasure Plan by owners or operators.

If you are the owner or operator of a facility subject to this part, you must:

(a) Amend the SPCC Plan for your facility in accordance with the general requirements in § 112.7, and with any specific section of this part applicable to your facility, when there is a change in the facility design, construction, operation, or maintenance that materially affects its potential for a discharge as described in § 112.1(b). Examples of changes that may require amendment of the Plan include, but are not limited to: commissioning or decommissioning containers; replacement, reconstruction, or movement of containers; reconstruction, replacement, or installation of piping systems; construction or demolition that might alter secondary containment structures; changes of product or service; or revision of standard operation or maintenance procedures at a facility. An amendment made under this section must be prepared within six months, and implemented as soon as possible, but not later than six months following preparation of the amendment.

(b) Notwithstanding compliance with paragraph (a) of this section, complete a review and evaluation of the SPCC Plan at least once every five years from the date your facility becomes subject to this part; or, if your facility was in operation on or before August 16, 2002, five years from the date your last review was required under this part. As a result of this review and evaluation, you must amend your SPCC Plan within six months of the review to include more effective prevention and control technology if the technology has been field-proven at the time of the review and will significantly reduce the likelihood of a discharge as described in § 112.1(b) from the facility. You must implement any amendment as soon as possible, but not later than six months following preparation of any amendment. You must document your completion of the review and evaluation, and must sign a statement as to whether you will amend the Plan, either at the beginning or end of the Plan or in a log or an appendix to the Plan. The following words will suffice, “I have completed review and evaluation of the SPCC Plan for (name of facility) on (date), and will (will not) amend the Plan as a result.”

(c) Have a Professional Engineer certify any technical amendment to your Plan in accordance with § 112.3(d).

♦ § 112.5 ~ Amendment of Spill Prevention, Control, and Countermeasure Plan by Owners or Operators ♦

§ 112.5 requires the installation to amend the SPCC Plan within six months when there is a change in facility design, construction, operation, or maintenance that could affect the potential for discharge. Example of changes that may require amendment of the SPCC Plan include:

- **Commissioning or decommissioning containers.**
- **Replacement, reconstruction, or movement of containers.**
- **Replacement, reconstruction, or movement of piping systems.**
- **Construction or demolition that might alter secondary containment structures.**
- **Changes of product or service.**
- **Revision of standard operation or maintenance procedures.**

Any amendments that are technical in nature (i.e., require exercising good engineering practice) must be certified by a PE. Non-technical changes, such as changes in contact lists, phone numbers, or other changes that do not materially affect the facility's potential to discharge oil, do not need to be certified by a PE.

The owner or operator must conduct a complete review and evaluation of the SPCC Plan every 5 years and state (i.e., document in writing) whether or not a revision or amendment is necessary. Non-technical changes may be made by the owner or operator, and would not require certification by a PE. Any technical changes (typically made by the PE or an agent of the PE) would require certification by the PE. Therefore SPCC Plans (or Plan amendments) must only be certified by a PE if technical changes to the Plan have occurred.

§ 112.6 [Reserved]

♦ § 112.6 ~ [Reserved] ♦

§ 112.6 contains no requirements.

§ 112.7 General requirements for Spill Prevention, Control, and Countermeasure Plans.

If you are the owner or operator of a facility subject to this part you must prepare a Plan in accordance with good engineering practices. The Plan must have the full approval of management at a level of authority to commit the necessary resources to fully implement the Plan. You must prepare the Plan in writing. If you do not follow the sequence specified in this section for the Plan, you must prepare an equivalent Plan acceptable to the Regional Administrator that meets all of the applicable requirements listed in this part, and you must supplement it with a section cross-referencing the location of requirements listed in this part and the equivalent requirements in the other prevention plan. If the Plan calls for additional facilities or procedures, methods, or equipment not yet fully operational, you must discuss these items in separate paragraphs, and must explain separately the details of installation and operational start-up. As detailed elsewhere in this section, you must also:

♦ § 112.7 ~ General Requirements for Spill Prevention, Control, and Countermeasure Plans ♦

§ 112.7 requires the preparation of an SPCC Plan in accordance with good engineering practice, and suggests following the sequence outlined in § 112.7 is highly preferable. If this sequence is

not followed, an equivalent plan that contains all required information must be prepared, and supplemented with a section cross-referencing components of the equivalent plan to the location of all § 112.7 requirements. Neither equivalent plans nor the preferred sequential plans are required to be submitted to the EPA for approval, but the EPA does reserve the right to disagree with the format and/or organization of any plan it reviews and request timely modification.

(a)

(1) Include a discussion of your facility's conformance with the requirements listed in this part.

♦ § 112.7(a)(1) ~ General Requirements ♦

§ 112.7(a)(1) requires a discussion of how the installation conforms to Part 112 requirements. Describe why the installation must conform to the requirements set forth in Part 112 and how the requirements are met. Identify and discuss any deviations from requirements (i.e., nonconformance) that result from exercising the provisions of § 112.7(a)(2) in the following section.

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(2) Comply with all applicable requirements listed in this part. Your Plan may deviate from the requirements in paragraphs (g), (h)(2) and (3), and (i) of this section and the requirements in subparts B and C of this part, except the secondary containment requirements in paragraphs (c) and (h)(1) of this section, and §§ 112.8(c)(2),112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), 112.12(c)(11),112.13(c)(2), and 112.14(c), where applicable to a specific facility, if you provide equivalent environmental protection by some other means of spill prevention, control, or countermeasure. Where your Plan does not conform to the applicable requirements in paragraphs (g), (h)(2) and (3), and (i) of this section, or the requirements of subparts B and C of this part, except the secondary containment requirements in paragraphs (c) and (h)(1) of this section, and §§ 112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), 112.12(c)(11), 112.13(c)(2), and 112.14(c), you must state the reasons for nonconformance in your Plan and describe in detail alternate methods and how you will achieve equivalent environmental protection. If the Regional Administrator determines that the measures described in your Plan do not provide equivalent environmental protection, he may require that you amend your Plan, following the procedures in § 112.4(d) and (e).

♦ § 112.7(a)(2) ~ Deviations from Plan Requirements ♦

§ 112.7(a)(2) asserts that an installation may deviate from some of the requirements of Part 112. A deviation may generally be used wherever the reason for nonconformance can be adequately explained and equivalent environmental protection is provided.

However, § 112.7(a)(2) does not allow deviations for the secondary containment requirements in Part 112 (i.e., § 112.7(c), Secondary Containment; § 112.7(h)(1), Loading/Unloading (Excluding Offshore Facilities); § 112.8(c)(2), Secondary Containment – Bulk Storage Containers; and § 112.8(c)(11), Mobile Containers). Note that costs or economic impacts are <u>not</u> excluded justifications as to why an installation cannot satisfy a specific requirement (again, with the exception of secondary containment requirements).

Specific examples of 'equivalent environmental protection' by some other means of spill prevention, control, or countermeasure have nowhere been defined or officially

endorsed. Rather, the EPA allows for an assortment of inventive substitutions or situational solutions, provided the equivalent environmental protection can be adequately explained. Of course, any deviations and the equivalent substitutions must be supported by the certifying PE, applying good engineering judgment and consideration of applicable industry standards, and be described in the SPCC Plan.

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(3) Describe in your Plan the physical layout of the facility and include a facility diagram, which must mark the location and contents of each container. The facility diagram must include completely buried tanks that are otherwise exempted from the requirements of this part under § 112.1(d)(4). The facility diagram must also include all transfer stations and connecting pipes. You must also address in your Plan:

(i) The type of oil in each container and its storage capacity;

(ii) Discharge prevention measures including procedures for routine handling of products (loading, unloading, and facility transfers, *etc*.);

(iii) Discharge or drainage controls such as secondary containment around containers and other structures, equipment, and procedures for the control of a discharge;

(iv) Countermeasures for discharge discovery, response, and cleanup (both the facility's capability and those that might be required of a contractor);

(v) Methods of disposal of recovered materials in accordance with applicable legal requirements; and

(vi) Contact list and phone numbers for the facility response coordinator, National Response Center, cleanup contractors with whom you have an agreement for response, and all appropriate Federal, State, and local agencies who must be contacted in case of a discharge as described in § 112.1(b).

♦ § 112.7(a)(3) ~ Facility Characteristics That Must be Described in the Plan ♦

§ 112.7(a)(3) requires the physical layout of the installation be described, and further defines what must be included in a facility diagram. For smaller Navy or Marine Corps installations, a single facility diagram may be sufficient; for larger installations, or installations with dispersed or isolated, or complex oil storage locations, a set of diagrams may be necessary.

It is necessary to include the location and type of oil (and name, if appropriate) of each container on a facility diagram or set of diagrams. Note that underground storage tanks (USTs) regulated under federal or state UST regulations do not have to be included in the SPCC Plan, but their location and contents must be indicated on a facility diagram or set of diagrams. Bulk storage containers as well as oil-filled electrical and other operating equipment that are 55 gal or greater must be placed on the facility diagram or set of diagrams. In addition, areas where mobile or portable (i.e., not "fixed") containers are stored need to be included on the facility diagram or set of diagrams.

It may be not practicable, and is not required, to include all the other details listed in § 112.7(a)(3) on the facility diagram because of diagram scale or available diagram space. Possible approaches for presenting the required details:

- **Include 'site-specific' or 'tank-specific' sections later in the Plan where these details can be adequately addressed individually. Clearly indicate / reference in this section exactly where these details can be found in the Plan.**
- **List the pertinent details of relevant sites or tanks collectively within this section. Tables or matrices addressing the required details could be created to clearly identify the attributes of each oil storage location.**
- **Develop a combination of the above two bullets by both presenting information collectively in this section (e.g., in the form of tables or matrices), as well as referencing individual site-specific or tank-specific sections. The benefit of the combination approach is that a collective summary of installation information, often sought by regulators or external users of SPCC Plan information, is readily available, in addition to individual detailed oil storage information, often more useful to installation personnel.**

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(4) Unless you have submitted a response plan under § 112.20, provide information and procedures in your Plan to enable a person reporting a discharge as described in § 112.1(b) to relate information on the exact address or location and phone number of the facility; the date and time of the discharge, the type of material discharged; estimates of the total quantity discharged; estimates of the quantity discharged as described in § 112.1(b); the source of the discharge; a description of all affected media; the cause of the discharge; any damages or injuries caused by the discharge; actions being used to stop, remove, and mitigate the effects of the discharge; whether an evacuation may be needed; and, the names of individuals and/or organizations who have also been contacted.

♦ § 112.7(a)(4) ~ Spill Reporting Information in the Plan ♦

§ 112.7(a)(4) stipulates that unless your installation submits a Facility Response Plan (FRP), the SPCC Plan must include information and procedures enabling a person reporting a discharge to readily reference and relate the following:

- **Exact address or location and phone number of the facility.**
- **The date and time of the discharge.**
- **The type of material discharged.**
- **Estimates of the total quantity discharged.**
- **Estimates of the total quantity discharged to navigable waters.**
- **The source of the discharge.**
- **A description of all affected media.**
- **The cause of the discharge.**
- **Any damages or injuries caused by the discharge.**
- **Actions being used to stop, remove, and mitigate the effects of the discharge.**
- **Whether an evacuation may be needed.**
- **The names of individuals and/or organizations who have also been contacted.**

A blank form (such as the sample included in Section 4 Appendix G) to fill in the above information may be included as an appendix to the SPCC Plan, but clearly reference it from this section. Refer to Section 4 Appendix E of this document for guidance on determining whether your facility must prepare an FRP.

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(5) Unless you have submitted a response plan under § 112.20, organize portions of the Plan describing procedures you will use when a discharge occurs in a way that will make them readily usable in an emergency, and include appropriate supporting material as appendices.

♦ § 112.7(a)(5) ~ Emergency Procedures ♦

§ 112.7(a)(5) states that unless your installation maintains and follows an FRP, the SPCC Plan must describe procedures to follow when a discharge occurs. These procedures should be readily available in an emergency, and include appropriate supporting material as appendices. Refer to Section 4 Appendix E of this document for guidance on determining whether your facility must prepare an FRP.

Spill reporting is required under Section 311(b)(5) of the Clean Water Act (CWA) and is an essential tool for spill prevention and expeditious response to potential or actual spills. A spill reporting system serves the following purposes:

- **Notify appropriate area personnel to initiate immediate action.**
- **Ensure timely notification to all Navy commands and regulatory agencies.**
- **Identify and correct causes to prevent or minimize recurrence.**
- **Identify necessary revisions to the SPCC Plan.**

The names, titles, and duty / off-duty telephone numbers of key area and activity personnel to whom spills must be reported are supporting information that should be included as appendices to the SPCC Plan. Contacts at regulatory agencies and other concerned authorities / organizations to be notified and the circumstances that require their notification should also be included as supporting material.

(b) Where experience indicates a reasonable potential for equipment failure (such as loading or unloading equipment, tank overflow, rupture, or leakage, or any other equipment known to be a source of a discharge), include in your Plan a prediction of the direction, rate of flow, and total quantity of oil which could be discharged from the facility as a result of each type of major equipment failure.

♦ § 112.7(b) ~ Fault Analysis ♦

§ 112.7(b) requires a prediction of the direction, rate of flow, and total quantity of oil that could be discharged from the facility as a result of each type of major equipment failure. Major equipment failure includes failures of loading/unloading equipment, or any other equipment known by the facility or industry to be a source of discharge.

Examples of major equipment failure include:

- **Overfill via tank truck.**
- **Overfill via piping.**
- **Tank rupture or leakage.**
- **Valve or piping failure.**

The SPCC Plan should identify the largest spill expected at each facility. The maximum possible spill quantity is the total capacity of the largest holding unit at the area; it is not the largest volume typically stored. Examples include the largest tank in a tank farm or the largest compartment of a tank truck.

The behavior of spilled oil is influenced by the type of material spilled, the cause of the spill, the features of the area, and the terrain surrounding the area. The direction in which a spill will spread is determined by natural and man-made drainage patterns that surround

the area. These may be influenced by items such as:

- **Ground slope or grade.**
- **Streams or rivers.**
- **Dry creek beds.**
- **Hills.**
- **Spill containment structures.**
- **Curbs.**
- **Ditches.**
- **Sanitary and storm sewers.**
- **Floor drains**
- **Ground condition (e.g., loose, hard, asphalt, concrete, thick weeds, grass, sand, rocks)**

The required details (direction, rate of flow, and total quantity of oil that could be discharged) may be addressed by one of several approaches:

- **Include 'site-specific' or 'tank-specific' sections later in the Plan where these details can be adequately addressed individually. Clearly indicate / reference in this section exactly where these details can be found in the Plan.**
- **List the pertinent details of relevant sites or tanks collectively within this section. Tables or matrices addressing the required details could be created to clearly identify the attributes of each oil storage location.**
- **Develop a combination of the above two bullets by both presenting information collectively in this section (e.g., in the form of tables or matrices), as well as referencing individual site-specific or tank-specific sections. The benefit of the combination approach is that a collective summary of installation information, often sought by regulators or external users of SPCC Plan information, is readily available, in addition to individual detailed oil storage information, often more useful to installation personnel.**

Chapter 6 of the Spill Prevention Guidance Document (NFESC, 1998) contains discussion and provides guidance on spill prediction [http://enviro.nfesc.navy.mil/ps/spillprev].

(c) Provide appropriate containment and/or diversionary structures or equipment to prevent a discharge as described in § 112.1(b). The entire containment system, including walls and floor, must be capable of containing oil and must be constructed so that any discharge from a primary containment system, such as a tank or pipe, will not escape the containment system before cleanup occurs. At a minimum, you must use one of the following prevention systems or its equivalent:

(1) For onshore facilities:

(i) Dikes, berms, or retaining walls sufficiently impervious to contain oil;

(ii) Curbing;

(iii) Culverting, gutters, or other drainage systems;

(iv) Weirs, booms, or other barriers;

(v) Spill diversion ponds;

(vi) Retention ponds; or

(vii) Sorbent materials.

(2) For offshore facilities:

(i) Curbing or drip pans; or

(ii) Sumps and collection systems.

♦ § 112.7(c) ~ Secondary Containment ♦

§ 112.7(c) requires containment and/or diversionary structures be provided to prevent the discharge of oil to navigable waters. At minimum, one of the following prevention systems must be used:

- **Dikes, berms, or retaining walls sufficiently impervious to contain oil.**
- **Curbing.**
- **Culverting, gutters, or other drainage systems.**
- **Weirs, booms, or other barriers.**
- **Spill diversion ponds.**
- **Retention ponds**
- **Sorbent materials.**

This requirement applies only to oil storage locations from which a spill or release might reasonably be expected to reach navigable waters. For example, transformers or oil-filled electrical switchboxes that do not pose a threat of discharge to navigable waters (e.g., do not have potential to travel through stormwater drains or overland into navigable waters) would not be required to install containment systems.

Although not specifically identified as secondary containment systems in § 112.7(c), buildings may themselves be adequate diversionary structures, exhibiting the containment characteristics of dikes, retaining walls, or other barriers. However, the floors and walls of the structure would have to be sufficiently impervious to contain oil (e.g., free of floor drains, cracks, and porous joints or gaps).

An installation may not use the deviation rule under § 112.7(a)(2) to deviate from this secondary containment requirement (e.g., may not consider cost or economic impacts in determining feasibility), but may use the deviation rule under § 112.7(d) where secondary containment is considered not practicable (see Section 2 Page 22 for justifiable reasons). For any deviation, clearly explain in the SPCC Plan how 'equivalent environmental protection' is provided.

Refer to the following industry standards for further guidance on secondary containment: Section 7 of API Standard 2610, "Design, Construction, Operation, Maintenance, and Inspection of Terminal & Tank Facilities" and Chapter 2 of NFPA 30, "Flammable and Combustible Liquids Code".

Section 4.2.9 of the Spill Prevention Guidance Document (NFESC, 1998) discusses secondary containment for bulk oil storage tanks. Chapter 7 contains discussion and provides guidance on identification and evaluation of possible deficiencies of the spill containment systems listed above [http://enviro.nfesc.navy.mil/ps/spillprev].

<u>Cost Information</u>
Information on numerous approaches to secondary containment and related items is

included in Section 4 Appendix A. Approaches and items discussed include:

- **Portable containment berms: $200 - $1,400 for smaller berms, $3,000 - $7,000 for larger berms (per vendors).**
- **Drum containment pallets and pallet inserts: $150 - $600 for pallets accommodating 2 - 4 drums, $450 - $600 for pallet inserts containing 55 - 80 gal (per vendors).**
- **Spill kits: $100 - $1,000 per spill kit (per vendors).**
- **Drain covers: $100 - $500 per cover (per vendors).**
- **Concrete berm design: $3,130 - $10,239 for tank capacities of 500 - 5,000 gal (per PWD).**
- **Masonry berm design: $1,547 - $2,686 for tank capacities of 250 - 1,000 gal (per PWD).**
- **Rollover (drivable) berm design for loading/unloading areas: $3,775 - $11,713 for tank capacities of 1,000 - 5,000 gal (per PWD).**
- **Earth berm design: $857 - $1,322 for tank capacities of 250 - 1,000 gal (per PWD).**
- **Repair or sealing of cracks and fissures: $30 - $35 per linear foot (per PWD).**
- **Doorway spill barriers: $2,985 - $10,909 for manual or automatic barriers from 3' - 10' wide (per vendors).**
- **Oil-swellable absorbent polymer storm drain inserts: $800 - $10,000 for drain protection shut-off systems or $81 - $227 for Imbiber Bead packets, pillows, blankets, boom, etc. (per vendors).**

(d) If you determine that the installation of any of the structures or pieces of equipment listed in paragraphs (c) and (h)(1) of this section, and §§ 112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), 112.12(c)(11), 112.13(c)(2), and 112.14(c) to prevent a discharge as described in § 112.1(b) from any onshore or offshore facility is not practicable, you must clearly explain in your Plan why such measures are not practicable; for bulk storage containers, conduct both periodic integrity testing of the containers and periodic integrity and leak testing of the valves and piping; and, unless you have submitted a response plan under § 112.20, provide in your Plan the following:

(1) An oil spill contingency plan following the provisions of part 109 of this chapter.

(2) A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

♦ § 112.7(d) ~ Deviation from Secondary Containment Requirement (Contingency Planning) ♦

§ 112.7(d) states that if installation of any containment structures or pieces of equipment are determined to be not practicable, a clear explanation of why such measures are not practicable must be provided in the Plan. The reason for nonconformance must be justified, and alternate methods of 'equivalent environmental protection' must be provided. For bulk storage containers, periodic integrity testing of the containers must be conducted, as must periodic integrity testing and leak testing of the valves and piping. Unless you have an FRP you must also:

- **Provide an Oil Spill Contingency Plan, following 40 CFR 109.**
- **Provide a written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be helpful.**

Costs or economic impacts are excluded justifications as to why an installation cannot

satisfy the secondary containment requirement. Justifiable reasons why secondary containment may be considered not practicable include:

- **Space or other geographic limitations of the facility.**
- **Local zoning ordinances, fire prevention standards, or safety considerations.**
- **Installation would defeat the overall goal of 40 CFR 112 to prevent discharges.**

Examples of 'equivalent environmental protection' by some other means of spill prevention, control, or countermeasure have nowhere been defined or officially endorsed. Rather, the EPA allows for an assortment of inventive substitutions or situational solutions, provided the equivalent environmental protection can be adequately explained. Of course, any deviations and the equivalent substitutions must be supported by the certifying PE, applying good engineering judgement. Suggested methods of equivalent environmental protection, in the context of contingency planning, may include:

- **Frequent and/or enhanced monitoring of the facility by personnel.**
- **Implementation of a strong preventive maintenance and inspection program.**
- **Development of a strong contingency plan in the event of a discharge, locating spill response materials nearby at minimum.**
- **Frequent personnel training on spill prevention methods and spill response.**
- **Placement of drain covers (i.e., drain blockers, plug rugs) over storm drains and/or closing separator outlets during transfer operations.**

The absence of secondary containment places extreme importance on the early detection of an oil discharge and rapid response by the facility to prevent that discharge. Where secondary containment is lacking, describe a contingency plan to be followed in the event of a discharge, including a written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

The absence of secondary containment also places extreme importance on the condition of storage containers, valves, and piping. To ensure all equipment is in good working condition, periodic integrity testing on bulk storage containers, and integrity and leak testing on valves and piping, must be conducted. Where secondary containment is determined to be not practicable, describe the testing performed and frequency of testing in this section. Note that per EPA policy (see Section 4 Appendix F), 55 gal drums with secondary containment (e.g., placed on spill containment pallets) that are visible from all sides to allow periodic inspections do not require integrity testing.

Refer to the following industry standards for further guidance on testing methods and appropriate frequencies: Section 12 of API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction"; API 570, "Piping Inspection Code – Inspection, Repair, Alteration, and Rerating of In-service Piping Systems"; Section 3 of API Recommended Practice 1110, "Pressure Testing of Liquid Petroleum Pipelines"; Chapter 4 of ASME B31.3, "Process Piping"; and Section 5.0 of STI SP001-00, "Standard for Inspection of In-Service Shop Fabricated Aboveground Tanks for Storage of Combustible and Flammable Liquids".

<u>Cost Information</u>
As noted above, bulk storage containers deviating from secondary containment requirements must have periodic integrity testing, and associated valves and piping must have periodic integrity testing and leak testing. Information on integrity testing is included in Section 4 Appendix A. Items discussed include:

- **Integrity testing of tanks → Non-destructive shell testing: $10,000 - $30,000 per tank**

for API 653 inspections of large tanks plus $5,000 - $20,000 for tank cleaning (per NFESC), $500 - $2,500 per tank (per Navy Environmental Requirements Guidebook).

- **Leak testing of valves and piping: $200 - $1,000 per pipe segment, $40,000 - $1M for installation of permanent release detection systems for large underground piping systems (per Navy Environmental Requirements Guidebook), $465 per tank for buried piping (per EPA).**

(e) *Inspections, tests, and records.* Conduct inspections and tests required by this part in accordance with written procedures that you or the certifying engineer develop for the facility. You must keep these written procedures and a record of the inspections and tests, signed by the appropriate supervisor or inspector, with the SPCC Plan for a period of three years. Records of inspections and tests kept under usual and customary business practices will suffice for purposes of this paragraph.

♦ § 112.7(e) ~ Inspections, Tests, and Records ♦

§ 112.7(e) requires inspections and tests be developed by the installation and/or the certifying PE. Keep these written procedures and records of the inspections and tests, signed by the appropriate [licensed] inspector, with the SPCC Plan for at least 3 years. Records of inspections and tests kept under usual and customary business practices are also acceptable.

Per API 653, usual and customary business records may include construction records, inspection history, and repair / alteration history. Schedules, evaluations, examinations, descriptions, and records of other activities required by Part 112 provide valuable information and history and should be retained in a file. Refer to Section 6 of API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction" for examples of inspection techniques and guidance on record keeping. Section 4.0 of STI SP001-00, "Standard for Inspection of In-Service Shop Fabricated Aboveground Tanks for Storage of Combustible and Flammable Liquids" describes monthly, quarterly, and annual AST inspections.

Sections 4.2.10, 4.2.11, and 4.2.12 of the Spill Prevention Guidance Document (NFESC, 1998) discuss tank system testing, tank inspections, and leak detection and monitoring, respectively. Sections 10.5 and 10.6 discuss inspections and record keeping requirements, respectively [http://enviro.nfesc.navy.mil/ps/spillprev].

(f) *Personnel, training, and discharge prevention procedures*

(1) At a minimum, train your oil-handling personnel in the operation and maintenance of equipment to prevent discharges; discharge procedure protocols; applicable pollution control laws, rules, and regulations; general facility operations; and, the contents of the facility SPCC Plan.

(2) Designate a person at each applicable facility who is accountable for discharge prevention and who reports to facility management.

(3) Schedule and conduct discharge prevention briefings for your oil-handling personnel at least once a year to assure adequate understanding of the SPCC Plan for that facility. Such briefings must highlight and describe known discharges as described in § 112.1(b) or failures, malfunctioning components, and any recently developed precautionary measures.

♦ § 112.7(f) ~ Employee Training and Discharge Prevention Procedures ♦

§ 112.7(f) requires oil-handling personnel be adequately trained at least annually. Training must include, at minimum:

- **The operation and maintenance of equipment to prevent the discharge of oil.**
- **Discharge procedure protocols.**
- **Applicable pollution control laws, rules, and regulations.**
- **General facility operations.**
- **Contents of the SPCC Plan.**
- **Discussion of any recent discharges, failures, or malfunctions, and lessons learned as a result.**
- **Discussion of any recently developed precautionary measures.**

Note that this is somewhat of a relaxation from earlier or proposed requirements; now only oil-handling personnel, as opposed to all personnel at the facility, are required to obtain annual training.

Section 10.3 of the Spill Prevention Guidance Document (NFESC, 1998) contains discussion and provides guidance on spill prevention training including chemical and physical properties of stored materials, emergency procedures, inspection procedures, overview of laws and regulations, and safety and health [http://enviro.nfesc.navy.mil/ps/spillprev].

(g) *Security (excluding oil production facilities)*

(1) Fully fence each facility handling, processing, or storing oil, and lock and/or guard entrance gates when the facility is not in production or is unattended.

(2) Ensure that the master flow and drain valves and any other valves permitting direct outward flow of the container's contents to the surface have adequate security measures so that they remain in the closed position when in non-operating or non-standby status.

(3) Lock the starter control on each oil pump in the "off" position and locate it at a site accessible only to authorized personnel when the pump is in a non-operating or non-standby status.

(4) Securely cap or blank-flange the loading/unloading connections of oil pipelines or facility piping when not in service or when in standby service for an extended time. This security practice also applies to piping that is emptied of liquid content either by draining or by inert gas pressure.

(5) Provide facility lighting commensurate with the type and location of the facility that will assist in the:

(i) Discovery of discharges occurring during hours of darkness, both by operating personnel, if present, and by non-operating personnel (the general public, local police, etc.); and

(ii) Prevention of discharges occurring through acts of vandalism.

♦ § 112.7(g) ~ Security (Excluding Oil Production Facilities) ♦

§ 112.7(g) requires specific security measures be in place at oil storage facilities, pertaining to fencing, valve locking, pump starter control locking, capping of piping connections, and lighting.

Navy and Marine Corps installations are typically surrounded by secure fencing, and are adequately patrolled by security personnel. With regard to access, this provides sufficient security for many sites and tanks. However, it is often necessary to provide additional security for critical or large oil storage locations, and oil-filled electrical equipment; these sites or tanks should be individually fenced and secured.

Secure valve locking, pump starter control locking, piping connection capping, and adequate lighting must be investigated and verified where appropriate. The security requirements may be addressed in the Plan by one of several approaches:

- **Include 'site-specific' or 'tank-specific' sections later in the Plan where these details can be adequately addressed individually. Clearly indicate / reference in this section exactly where these details can be found in the Plan.**
- **List the pertinent details of relevant sites or tanks collectively within this section. Tables or matrices addressing the required details could be created to clearly identify the attributes of each oil storage location.**
- **Develop a combination of the above two bullets by both presenting information collectively in this section (e.g., in the form of tables or matrices), as well as referencing individual site-specific or tank-specific sections. The benefit of the combination approach is that a collective summary of installation information, often sought by regulators or external users of SPCC Plan information, is readily available, in addition to individual detailed oil storage information, often more useful to installation personnel.**

Note that there may be defensible reasons (e.g., spatial limitations, safety concerns, costs or economic impacts) why an installation might not be able to satisfy a security requirement. In such instances, a clear explanation of why such measures are not practicable must be provided in the Plan. The reason for nonconformance must be justified, and alternate methods of 'equivalent environmental protection' must be provided (refer to § 112.7(a)(2)).

Chapter 9 of the Spill Prevention Guidance Document (NFESC, 1998) contains discussion and provides guidance on security including fencing, gates, equipment and building security, lighting, and security patrols [http://enviro.nfesc.navy.mil/ps/spillprev].

<u>Cost Information</u>
Information on several security measures and related items is included in Section 4 Appendix A. Measures and items discussed include:

- **Fencing: $20 - $30 per linear foot (per PWD).**
- **Valve lockouts: $18 - $70 for 1" - 13" lockouts (per vendors).**
- **Padlocks: $5 - $20 per padlock (per vendors).**
- **Lighting: $75 - $650 for fixtures, $480 - $1,335 for aluminum poles, or $4,395 - $5,146 installed for fixtures and poles (per National Construction Estimator).**

(h) *Facility tank car and tank truck loading/unloading rack (excluding offshore facilities)*

(1) Where loading/unloading area drainage does not flow into a catchment basin or treatment facility designed to handle discharges, use a quick drainage system for tank car or tank truck loading and unloading areas. You must design any containment system to hold at least the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded at the facility.

(2) Provide an interlocked warning light or physical barrier system, warning signs, wheel chocks, or vehicle break interlock system in loading/unloading areas to prevent vehicles from departing before complete disconnection of flexible or fixed oil transfer lines.

(3) Prior to filling and departure of any tank car or tank truck, closely inspect for discharges the lowermost drain and all outlets of such vehicles, and if necessary, ensure that they are tightened, adjusted, or replaced to prevent liquid discharge while in transit.

♦ § 112.7(h) ~ Loading/Unloading (Excluding Offshore Facilities) ♦

§ 112.7(h) lists spill prevention measures that must be in place for loading/unloading racks. For each loading/unloading rack at the installation, describe the individual arrangements, clearly detailing:

- **The containment system that holds at least the maximum capacity of any single vehicle compartment.**
- **All components of the transfer disconnection warning system.**
- **Inspection procedures prior to filling and departure of the vehicle.**

The EPA generally defines a loading/unloading rack as a facility where oil is loaded to or from tank trucks (or tank railcars). A more practical (i.e., suggested) definition of a loading/unloading rack for most Navy and Marine Corps installations, for the purposes of this section, would be a facility where tank trucks are filled from typically multiple tanks at a fillstand type rack.

Examples of facilities that might be considered loading/unloading racks, depending on operations and loading/unloading configuration, include fuel farms, Bilge and Oily Wastewater Treatment Systems (BOWTS), industrial wastewater treatment plants (IWTP), etc. Examples of facilities that would not be defined as loading/unloading racks (even if oil is delivered by tank truck) include solitary aboveground storage tanks (ASTs), aircraft hot pit sites, gas station ASTs used only for filling small vehicles, lube oil dispensing racks (e.g., in automotive shops), petroleum oil lubricant (POL) drums, etc.

It is the Navy's interpretation that § 112.7(h) applies only to facility tank truck (and tank railcar) loading/unloading racks. Any other areas where oil is loaded or unloaded is subject to the general secondary containment requirements of § 112.7(c), and the container may be subject to the secondary containment requirements of § 112.8(c).

Note that there may be defensible reasons (e.g., spatial limitations or safety concerns) why an installation might not be able to satisfy a loading/unloading requirement. Costs or economic impacts are not excluded reasons why an installation cannot satisfy § 112.8(h)(2) or § 112.8(h)(3), but are excluded reasons for not meeting the secondary containment requirement of § 112.8(h)(1). In any instances of deviations, a clear explanation of why such measures are not practicable must be provided in the Plan. The reason for nonconformance must be justified, and alternate methods of 'equivalent

environmental protection' must be provided (refer to § 112.7(a)(2)).

Sections 5.11 and 5.13 of the Spill Prevention Guidance Document (NFESC, 1998) discuss vehicle positioning and early departure prevention, and tank car and tank truck loading/ unloading racks [http://enviro.nfesc.navy.mil/ps/spillprev].

Refer also to the following sections of the Spill Prevention Resource Guide [NFESC, 2003] in Section 3 Tab B: Overfill Prevention; Loading Rack Devices (for Spill Prevention).

Cost Information
Information on several loading/unloading measures and related items is included in Section 4 Appendix A. Measures and items discussed include:

- **Overfill prevention: $18,000 for a Scully Signal system with Groundhog system (per NAS North Island).**
- **Vehicle brake interlock system: no cost data provided.**
- **Wheel chocks: $10 - $80 per set (per vendors).**
- **Warning signs: up to $150 per sign (per PWD).**

(i) If a field-constructed aboveground container undergoes a repair, alteration, reconstruction, or a change in service that might affect the risk of a discharge or failure due to brittle fracture or other catastrophe, or has discharged oil or failed due to brittle fracture failure or other catastrophe, evaluate the container for risk of discharge or failure due to brittle fracture or other catastrophe, and as necessary, take appropriate action.

♦ § 112.7(i) ~ Brittle Fracture Evaluation ♦

§ 112.7(i) requires field-constructed ASTs that may be subject to brittle fracture failure be evaluated for risk of discharge or catastrophic failure, in order to help prevent future failure.

Brittle fracture is a type of fracture that occurs where cracks rapidly propagate through a stressed material (i.e., there is very little plastic or ductile deformation before failure occurs). The cracks run perpendicular to the applied stress, leaving a relatively flat surface after the after the fracture. In many cases, brittle facture is the worst type of fracture, because visible damage in a part or structure cannot be repaired before it breaks. This type of fracture occurs under specific conditions without warning and can cause major damage.

Experience has shown that once a tank has demonstrated the ability to withstand the combined efforts of maximum liquid level (i.e., highest stress) and lowest operating temperature without failing, the risk of failure due to brittle fracture with continued service is minimal. However, any change in service must be evaluated to determine if it increases the risk of failure due to brittle fracture. In the event of a change to a more severe service (e.g., operating at a lower temperature, or handling product at a higher specific gravity) it is necessary to consider the need for a hydrostatic test to demonstrate fitness for a new more severe service.

Tanks are to be evaluated whenever repair, alteration, reconstruction, or change in service has occurred. Clarifications of these terms are provided below:

- ***Repair:*** **any work necessary to maintain or restore a container to a condition for safe**

operation, such as removal and replacement of material (e.g., roof, shell, or bottom material) to maintain container integrity; re-leveling or jacking of the container, shell, or bottom; addition of reinforcing plates to existing shell penetrations; or repair of flaws by grinding or gouging followed by welding.

- ***Alteration:*** **any work on a container involving cutting, burning, welding, or heating operations that change the physical dimensions or configurations of the container.**
- ***Reconstruction:*** **any work necessary to reassemble a tank that has been dismantled and relocated to a new site.**
- ***Change in Service:*** **any change from previous operating conditions involving different properties of the stored product (e.g., specific gravity, corrosivity) or service conditions (e.g., temperature, pressure).**

Section 5 of API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction" and API Recommended Practice 920 "Prevention of Brittle Fracture of Pressure Vessels" can be used to assist with brittle fracture evaluation. Brittle fracture evaluations of ASTs may be performed by Facilities or Public Works, Engineering Field Divisions (EFDs) or Naval Facilities Engineering Service Center (NFESC), or knowledgeable contractors or private engineering firms.

The SPCC Plan should include a discussion of which, if any, tanks at the installation may be susceptible to brittle fracture. Describe what measures are in place to address any warning signs of brittle fracture in facility ASTs.

<u>Cost Information</u>
Information on brittle fracture evaluation is included in Section 4 Appendix A:

- **Brittle fracture evaluation: $3,500 - $6,000 plus travel expenses for a 20,000 gal tank (per NFESC).**

(j) In addition to the minimal prevention standards listed under this section, include in your Plan a complete discussion of conformance with the applicable requirements and other effective discharge prevention and containment procedures listed in this part or any applicable more stringent State rules, regulations, and guidelines.

♦ § 112.7(j) ~ State Rules ♦

§ 112.7(j) requires a discussion of conformance with more stringent applicable State rules, regulations, and guidelines, if any. If more stringent State rules applicable to the installation do not exist, clearly state this.

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3. Part 112 is amended adding subpart B consisting of §§ 112.8 through 112.11 to read as follows:

Subpart B – Requirements for Petroleum Oils and Non-Petroleum Oils, Except Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and Vegetable Oils (Including Oils from Seeds, Nuts, Fruits, and Kernels)

Sec.
112.8 Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities).
112.9 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil production facilities.

112.10 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil drilling and workover facilities.
112.11 Spill Prevention, Control, and Countermeasure Plan requirements for offshore oil drilling, production, or workover facilities.

Subpart B – Requirements for Petroleum Oils and Non-Petroleum Oils, Except Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and Vegetable Oils (Including Oils from Seeds, Nuts, Fruits, and Kernels)

§ 112.8 Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities).

If you are the owner or operator of an onshore facility (excluding a production facility), you must:

♦ § 112.8 ~ Spill Prevention, Control, and Countermeasure Plan Requirements for Onshore Oil Production Facilities (Excluding Production Facilities) ♦

§ 112.8 applies to onshore facilities engaged in storing, transferring, distributing, using, or consuming oil and oil products. Most Navy and Marine Corps installations must follow the provisions of § 112.8.

(a) Meet the general requirements for the Plan listed under § 112.7, and the specific discharge prevention and containment procedures listed in this section.

♦ § 112.8(a) ~ General Requirements – Onshore Facilities (Excluding Production Facilities) ♦

§ 112.8(a) requires facilities adhere to the general requirements of § 112.7 as well as the specific discharge prevention and containment procedures of § 112.8.

(b) *Facility drainage*

(1) Restrain drainage from diked storage areas by valves to prevent a discharge into the drainage system or facility effluent treatment system, except where facility systems are designed to control such discharge. You may empty diked areas by pumps or ejectors; however, you must manually activate these pumps or ejectors and must inspect the condition of the accumulation before starting, to ensure no oil will be discharged.

♦ § 112.8(b)(1) ~ Diked Storage Area Drainage ♦

§ 112.8(b)(1) requires that diked secondary containment areas do not automatically empty when rainwater accumulates. Captured rainwater must be inspected prior to emptying to ensure no oil will be discharged.

Secondary containment dikes, berms, curbing, or walls that have holes or pipes installed to allow for easy drainage of captured rainwater must be fitted with valves (refer to § 112.8(b)(2)). Secondary containment without drainage holes or pipes may use pumps, ejectors, or other means to remove captured rainwater, provided they are manually activated.

Chapter 8 of the Spill Prevention Guidance Document (NFESC, 1998) contains discussion and provides guidance on drainage control and treatment units [http://enviro.nfesc.navy.mil/ps/spillprev].

Cost Information
Information on diked storage area drainage by pumps and ejectors is included in Section 4 Appendix A:

- **Pumps and ejectors: $150 - $450 (per vendors); $167 - $200 installed (per National Construction Estimator).**

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(2) Use valves of manual, open-and-closed design, for the drainage of diked areas. You may not use flapper-type drain valves to drain diked areas. If your facility drainage drains directly into a watercourse and not into an on-site wastewater treatment plant, you must inspect and may drain uncontaminated retained stormwater, as provided in paragraphs (c)(3)(ii), (iii), and (iv) of this section.

♦ § 112.8(b)(2) ~ Diked Storage Areas – Valves Used; Inspection of Retained Stormwater ♦

§ 112.8(b)(2) describes valve design for the drainage of diked areas. Secondary containment dikes, berms, curbing, or walls that have holes or pipes installed to allow for easy drainage of captured rainwater must be fitted with watertight manual open-and-closed valves. Lockable valves are highly preferable, since they will greatly improve the likelihood that the condition of the captured rainwater is inspected before emptying, and that the valve is closed upon completion of emptying.

Note that there may be defensible reasons (e.g., spatial limitations, safety concerns, costs or economic impacts) why a facility may deviate from the manual valve requirement for the drainage of diked areas. For example, watertight plugs or caps (preferably threaded and lockable) installed in the drainage holes or pipes could be acceptable alternatives to valves. In instances where drainage holes or pipes are in installed, but where manual valves are not used, a clear explanation of why such measures are not practicable must be provided in the Plan. The reason for nonconformance must be justified, and alternate methods of 'equivalent environmental protection' must be provided (refer to § 112.7(a)(2)).

Sections 8.2 and 8.3 of the Spill Prevention Guidance Document (NFESC, 1998) discuss collection and containment, and transfer of captured rainwater [http://enviro.nfesc.navy.mil/ps/spillprev].

Cost Information
Information relating to diked storage area drainage valves is included in Section 4 Appendix A. Items discussed include:

- **Drain outlets: $43 per 3" hole drilled through 6" concrete or masonry (per PWD).**
- **Manual open-and-closed valves: $5 - $70 per valve less than 3" in diameter (per vendors); $12 - $49 per valve installed less than 3" in diameter (per National Construction Estimator).**

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(3) Design facility drainage systems from undiked areas with a potential for a discharge (such as where piping is located outside containment walls or where tank truck discharges may occur outside the loading area) to flow into ponds, lagoons, or catchment basins designed to retain oil or return it to the facility. You must not locate catchment basins in areas subject to periodic flooding.

♦ § 112.8(b)(3) ~ Drainage Into Secondary Containment; Areas Subject to Flooding ♦

§ 112.8(b)(3) describes how facility drainage from undiked areas with a potential for discharge must be designed to flow into catchment. Examples of undiked areas include areas where single-walled piping is located outside containment walls, or where tank truck discharges may occur outside loading areas.

Note that there may be defensible reasons (e.g., spatial limitations, safety concerns, costs or economic impacts) why a facility may deviate from the requirement to design facility drainage from undiked areas to flow into catchment. In instances where facility drainage from undiked areas is not designed to flow into catchment, a clear explanation of why such a design is not practicable must be provided in the Plan. The reason for nonconformance must be justified, and alternate methods of 'equivalent environmental protection' must be provided (refer to § 112.7(a)(2)). The following section, § 112.8(b)(4), offers further guidance if facility drainage cannot be designed to flow into catchment.

Section 7.3 of the Spill Prevention Guidance Document (NFESC, 1998) discusses undiked area drainage [http://enviro.nfesc.navy.mil/ps/spillprev].

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(4) If facility drainage is not engineered as in paragraph (b)(3) of this section, equip the final discharge of all ditches inside the facility with a diversion system that would, in the event of an uncontrolled discharge, retain oil in the facility.

♦ § 112.8(b)(4) ~ Diversion Systems ♦

§ 112.8(b)(4) states that if facility drainage from undiked areas with a potential for discharge is not designed to flow into catchment, then the final discharge of all ditches inside the facility should be equipped with a diversion system.

Examples of diversion systems that could be used to fulfill this requirement include oil/water separators, boom (permanently installed on surface water), drain covers, etc.

However, note that oil/water separators might not reliably accommodate large slugs of oil (such as in a spill situations), and they should be properly sized for the facility. Oil/water separators have significant maintenance and cleaning requirements, and need specific operational controls developed for them to ensure they perform efficiently. Also, boom is more commonly utilized in spill response than in diversionary systems. Boom that is permanently installed on surface water (e.g., on water-filled drainage ditches leading to navigable waters) is typically an added diversionary measure, rather the primary measure of retaining oil from the watercourse.

<u>Cost Information</u>
Information relating to diversion systems or approaches is included in Section 4

Appendix A. Items discussed include:

- **Boom: $2 - $4 per linear foot for oil sorbent boom or socks, $7 - $16 per linear foot for containment boom (per vendors).**

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(5) Where drainage waters are treated in more than one treatment unit and such treatment is continuous, and pump transfer is needed, provide two "lift" pumps and permanently install at least one of the pumps. Whatever techniques you use, you must engineer facility drainage systems to prevent a discharge as described in § 112.1(b) in case there is an equipment failure or human error at the facility.

♦ § 112.8(b)(5) ~ Lift Pumps ♦

§ 112.8(b)(5) requires redundancy in "lift" pumps, where pump transfer is needed to facilitate continuous treatment of drainage waters in multiple treatment units.

Section 8.5 of the Spill Prevention Guidance Document (NFESC, 1998) discusses flow between treatment units [http://enviro.nfesc.navy.mil/ps/spillprev].

Cost Information
Information on lift pumps is included in Section 4 Appendix A:

- **Lift pumps → Pumps and ejectors: $150 - $450 for pumps with or without ejectors (per vendors); $167 - $200 installed for submersible sump pumps (per National Construction Estimator).**

(c) *Bulk storage containers*

(1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature.

♦ § 112.8(c)(1) ~ Construction of and Materials Used for Containers ♦

§ 112.8(c)(1) notes that only containers compatible with the oil being stored must be used. Generally, welded steel drums conforming to DOT specifications and ASTs conforming to API Standard 650 specifications are compatible containers for storing oil.

Refer to the following industry standards for further guidance on container material and construction: Sections 4 – 6 of API Standard 620, "Design and Construction of Large, Welded, Low-Pressure Storage Tanks"; Sections 2 – 5 of API Standard 650, "Welded Steel Tanks for Oil Storage"; and STI F911.

Section 4.2.1 of the Spill Prevention Guidance Document (NFESC, 1998) discusses tank construction and materials [http://enviro.nfesc.navy.mil/ps/spillprev].

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(2) Construct all bulk storage container installations so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must ensure that diked areas are sufficiently impervious to contain

discharged oil. Dikes, containment curbs, and pits are commonly employed for this purpose. You may also use an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a facility catchment basin or holding pond.

♦ § 112.8(c)(2) ~ Secondary Containment – Bulk Storage Containers ♦

§ 112.8(c)(2) requires all bulk storage container installations have secondary containment for the largest single container, plus sufficient freeboard to contain precipitation. Diked areas must also be sufficiently impervious to contain a discharge. Note that costs or economic impacts are not considered acceptable reasons for an installation to deviate from this secondary containment requirement by utilizing the deviation rule of § 112.7(a)(2).

Bulk storage containers are defined in § 112.2 as "any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container."

Oil-filled electrical transformers and switchboxes are not considered bulk storage containers, and are therefore not explicitly required to have secondary containment under § 112.8(c)(2). However, oil-filled electrical equipment that pose a threat of reaching navigable waters if a spill or discharge were to occur would be required to install containment systems under § 112.7(c). Also, tanks belonging to stationary emergency generator sets would generally qualify as bulk storage containers, not operating equipment.

The rationale behind including sufficient freeboard to contain precipitation within the secondary containment is that if a discharge were to occur during or just after a storm event (i.e., before the captured rainwater can be emptied), the secondary containment will be able to hold the precipitation and the discharge without overflowing. In designing a dike for this purpose, it is often adequate to design the dike to contain 110% of the contents of the largest single container. However, this may be insufficient if the dike area has a large footprint, or if the installation is located in a region subject to heavy or frequent rains. To ensure precipitation will be adequately accounted for, design the height of the dike to accommodate not only the volume of oil storage, but also the depth of rainfall associated with the 24-hour, 25-year storm event for the area. This can be interpolated from National Oceanic Atmospheric Administration (NOAA) Frequency Precipitation Atlases. Atlases for the 48 contiguous United States can be easily viewed online at various web sites, including the following:

[http://www.ncdc.noaa.gov/oa/documentlibrary/rainfall.html]

Diked areas must prevent discharges and precipitation from leaking out into the surrounding area or infiltrating into the soil beneath the containment area. Cracks or holes that develop must be properly repaired and sealed. Discharges that occur at remote or infrequently accessed bulk storage containers, or discharges occurring on weekends, holidays, or during the night must be fully retained by the secondary containment until it can be properly removed. A 72-hour impervious standard for the secondary containment was proposed by the EPA, but later dropped. [This 72-hour standard has been included here only to provide a frame of reference; there is no actual time interval defined or implied in § 112.8(c)(2).]

Although not specifically identified as secondary containment systems in § 112.7(c), buildings may themselves be adequate diversionary structures, exhibiting the containment characteristics of dikes, retaining walls, or other barriers. However, the floors and walls of the structure would have to be sufficiently impervious to contain oil (e.g., free of floor drains, cracks, and porous joints or gaps).

Section 4.2.9 of the Spill Prevention Guidance Document (NFESC, 1998) discusses secondary containment for bulk storage tanks. Chapter 7 contains discussion and provides guidance on identification and evaluation of possible deficiencies of various types of spill containment [http://enviro.nfesc.navy.mil/ps/spillprev].

Cost Information

Information on numerous approaches to secondary containment and related items is included in Section 4 Appendix A. Relevant approaches and items discussed under bulk storage containment include:

- **Portable containment berms: $200 - $1,400 for smaller berms, $3,000 - $7,000 for larger berms (per vendors).**
- **Drum containment pallets and pallet inserts: $150 - $600 for pallets accommodating 2 - 4 drums, $450 - $600 for pallet inserts containing 55 - 80 gal (per vendors).**
- **Spill kits: $100 - $1,000 per kit (per vendors).**
- **Drain covers: $100 - $500 per cover (per vendors).**
- **Concrete berm design: $3,130 - $10,239 for tank capacities of 500 - 5,000 gal (per PWD).**
- **Masonry berm design: $1,547 - $2,686 for tank capacities of 250 - 1,000 gal (per PWD).**
- **Rollover (driveable) berm design for loading/unloading areas: $3,775 - $11,713 for tank capacities of 1,000 - 5,000 gal (per PWD).**
- **Earth berm design: $857 - $1,322 for tank capacities of 250 - 1,000 gal (per PWD).**
- **Repair or sealing of cracks and fissures: $30 - $35 per linear foot (per PWD).**
- **Doorway spill barriers: $2,985 - $10,909 for manual or automatic barriers from 3' - 10' wide (per vendors).**
- **Oil-swellable absorbent polymer storm drain inserts: $800 - $10,000 for drain protection shut-off systems or $81 - $227 for Imbiber Bead packets, pillows, blankets, boom, etc. (per vendors).**

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(3) Not allow drainage of uncontaminated rainwater from the diked area into a storm drain or discharge of an effluent into an open watercourse, lake, or pond, bypassing the facility treatment system unless you:

(i) Normally keep the bypass valve sealed closed.

(ii) Inspect the retained rainwater to ensure that its presence will not cause a discharge as described in § 112.1(b).

(iii) Open the bypass valve and reseal it following drainage under responsible supervision; and

(iv) Keep adequate records of such events, for example, any records required under permits issued in accordance with §§ 122.41(j)(2) and 122.41(m)(3) of this chapter.

♦ § 112.8(c)(3) ~ Drainage of Rainwater ♦

§ 112.8(c)(3) specifies that uncontaminated rainwater collected in a diked area may be emptied only under the following circumstances:

- **The retained rainwater does not contain any oil or oily sheen.**
- **The drainage valve must be kept closed during normal operations, and must be resealed after emptying the retained rainwater.**
- **A record of the emptying operation must be kept.**

A logbook used to keep adequate records of emptying operations should capture the following information:

- **Date of the emptying operation.**
- **Name of personnel conducting the emptying operation.**
- **Location of the emptying operation.**
- **Condition of retained rainwater (i.e., verify no oily sheen present).**
- **Secondary containment is intact (i.e., verify no leaks from the dike).**
- **Uncontaminated rainwater has been completely emptied.**
- **Valve is closed upon completion of the emptying operation.**

Sections 8.2 and 8.3 of the Spill Prevention Guidance Document (NFESC, 1998) discuss collection and containment, and transfer of captured rainwater [http://enviro.nfesc.navy.mil/ps/spillprev].

(4) Protect any completely buried metallic storage tank installed on or after January 10, 1974 from corrosion by coatings or cathodic protection compatible with local soil conditions. You must regularly leak test such completely buried metallic storage tanks.

♦ § 112.8(c)(4) ~ Completely Buried Tanks; Corrosion Protection ♦

§ 112.8(c)(4) states that metallic USTs installed on or after 10 January 1974 must be protected from corrosion by coatings or cathodic protection, and must regularly be leak tested.

In most instances, completely buried USTs are subject to 40 CFR 280, Technical Standards and Corrective Action Requirements for Owners and Operators of Underground Storage Tanks. For these USTs, follow the corrosion protection provisions of Part 280, which provides comparable environmental protection to Part 112. Sections § 280.20 and § 280.21 require metallic USTs to have cathodic protection. Section § 280.31 requires all cathodic protection systems be tested within 6 months of installation and at least every 3 years thereafter. UST systems with impressed current cathodic protection systems must also be inspected every 60 days to ensure the equipment is running properly.

Field constructed USTs (whether completely or partially buried or bunkered) are excluded from Part 280, and are therefore, by default, covered under Part 112.

Refer to the following industry standards for further guidance on corrosion protection: API Recommended Practice 651, "Cathodic Protection of Aboveground Storage Tanks" and API Recommended Practice 652, "Lining of Aboveground Petroleum Storage Tank

Bottoms", and Section 10 of API Standard 2610, "Design, Construction, Operation, Maintenance, and Inspection of Terminal and Tank Facilities".

Section 4.2.4 of the Spill Prevention Guidance Document (NFESC, 1998) contains discussion and provides guidance on corrosion protection of tanks including fundamental concepts, protective coating systems, cathodic protection, and other systems. Sections 4.2.10.3, 4.2.11.3,and 4.2.12 discuss UST corrosion protection systems, UST inspection procedures, and leak detection and monitoring, respectively [http://enviro.nfesc.navy.mil/ps/spillprev].

Cost Information

Information on cathodic protection retrofitting, monitoring and testing, and related measures is included in Section 4 Appendix A. Section 4 Appendix C provides more detailed estimates on cathodic protection system surveys. Measures and approaches discussed include:

- **Cathodic protection retrofitting: 5% - 20% of the cost of a similar new installation, when retrofitting existing buried tanks and pipelines (per NFESC).**
- **Cathodic protection monitoring and testing: up to $8,000 for first time or full (annual) cathodic protection surveys for large tank farms, or up to $7,000 for extensive piping systems, not including travel or report expenses (per NFESC); $1,800 per year per tank for UST corrosion protection testing for impressed current systems, or $600 per year per tank for magnesium anode systems (per Navy Environmental Requirements Guidebook).**
- **Leak testing USTs and bunkered ASTs: $1,500 per year per tank for UST tightness testing and $750 per year per pipe run, $5,000 - $50,000 for periodic leak detection on large field-constructed USTs (per Navy Environmental Requirements Guidebook); $15,000 per 567,000 gal UST for tracer testing, or $3.76 per linear foot for pipeline tracer testing (per NAS North Island).**

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(5) Not use partially buried or bunkered metallic tanks for the storage of oil, unless you protect the buried section of the tank from corrosion. You must protect partially buried and bunkered tanks from corrosion by coatings or cathodic protection compatible with local soil conditions.

♦ § 112.8(c)(5) ~ Partially Buried or Bunkered Tanks; Corrosion Protection ♦

§ 112.8(c)(5) states that the buried portion of partially buried or bunkered metallic tanks, regardless of when they were installed, must be protected from corrosion by coatings or cathodic protection.

Partially buried or bunkered tanks are considered ASTs for Part 112, not USTs, and must therefore follow the corrosion protection provisions of this section. In terms of susceptibility to corrosion, however, they are essentially similar to USTs. Note that unlike 'completely buried tanks', described in § 112.8(c)(4), partially buried or bunkered tanks are not required to be regularly leak tested [by this section], although they are subject to the integrity testing requirements of § 112.8(c)(6)).

Although partially buried or bunkered tanks are considered ASTs for the purposes of Part 112, they may also be considered USTs for the purposes of Part 280 (and thereby subject to its provisions), if at least 10% of the tank (including piping) is underground. However, if the tank is less than 110 gal, or if it is a vaulted tank, it would not be covered under Part 280. Also, field constructed tanks (whether completely or partially

buried or bunkered) are excluded from Part 280, and are therefore, by default, covered under Part 112.

Describe how partially buried or bunkered tanks in use at the installation are protected from corrosion. A table or matrix addressing these details could be created to clearly identify the attributes of each tank. Alternately, if 'site-specific' or 'tank-specific' sections are included later in the Plan, these attributes could be adequately addressed individually (but clearly indicate / reference in this section exactly where these details can be found in the Plan).

Refer to the following industry standards for further guidance on corrosion protection: API Recommended Practice 651, "Cathodic Protection of Aboveground Storage Tanks" and API Recommended Practice 652, "Lining of Aboveground Petroleum Storage Tank Bottoms", and Section 10 of API Standard 2610, "Design, Construction, Operation, Maintenance, and Inspection of Terminal and Tank Facilities".

Section 4.2.4 of the Spill Prevention Guidance Document (NFESC, 1998) contains discussion and provides guidance on corrosion protection of tanks including fundamental concepts, protective coating systems, cathodic protection, and other systems. Sections 4.2.10.3, 4.2.11.3,and 4.2.12 discuss UST corrosion protection systems, UST inspection procedures, and leak detection and monitoring, respectively [http://enviro.nfesc.navy.mil/ps/spillprev].

<u>Cost Information</u>
Information on cathodic protection retrofitting, and related measures is included in Section 4 Appendix A. Relevant measures discussed include:

- **Partially buried or bunkered tanks → Cathodic protection retrofitting: 5% - 20% of the cost of a similar new installation, when retrofitting existing buried tanks and pipelines (per NFESC).**

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(6) Test each aboveground container for integrity on a regular schedule, and whenever you make material repairs. The frequency of and type of testing must take into account container size and design (such as floating roof, skid-mounted, elevated, or partially buried). You must combine visual inspection with another testing technique such as hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or another system of non-destructive shell testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of inspections and tests kept under usual and customary business practices will suffice for purposes of this paragraph.

♦ § 112.8(c)(6) ~ Integrity Testing ♦

§ 112.8(c)(6) specifies that aboveground containers must be tested for integrity on a regular schedule and whenever repairs are made. This must combine visual inspection with a non-destructive shell testing technique, for which records must be kept. The outside of the container, supports, and foundations must also be inspected frequently. Per EPA policy (see Section 4 Appendix F), 55 gal drums with secondary containment (e.g., placed on spill containment pallets) that are visible from all sides to allow periodic inspections do not require integrity testing.

Although § 112.8(c)(6) requires testing of "each aboveground container", this section falls under the general heading of § 112.8(c), Bulk Storage Containers. Therefore, it would not be appropriate to apply these integrity testing requirements to electrical or other operating equipment, even through they may be considered aboveground containers.

The following types of testing can be employed to determine the integrity of a container:

- **Hydrostatic Tests.**
- **Radiographic Tests.**
- **Ultrasonic Tests.**
- **Acoustic Emissions Tests.**
- **Other Non-Destructive Tests.**

Describe which specific integrity inspection techniques are used to inspect ASTs, and the frequency that these inspections occur. Also describe what external inspection techniques are used, and the frequency that these inspections occur. Maintain records of all AST inspections and tests.

Refer to Section § 112.7(d) for discussion of the general requirement for integrity testing bulk storage containers where secondary containment is not present.

Refer to the following industry standards for further guidance on AST testing methods and appropriate frequencies: Section 12 of API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction", and Section 5.0 of STI SP001-00, "Standard for Inspection of In-Service Shop Fabricated Aboveground Tanks for Storage of Combustible and Flammable Liquids".

Sections 4.2.10 and 4.2.11, and 4.2.12 of the Spill Prevention Guidance Document (NFESC, 1998) discuss tank system testing, tank inspections, and leak detection and monitoring, respectively. Sections 10.5.2 and 10.6 discuss visual tank inspections and record keeping requirements, respectively [http://enviro.nfesc.navy.mil/ps/spillprev].

<u>Cost Information</u>
Information on integrity testing and related measures is included in Section 4 Appendix A. Items discussed include:

- **Non-destructive shell testing: $10,000 - $30,000 per tank for API 653 inspections of large tanks, plus $5,000 - $20,000 for tank cleaning (per NFESC); $500 - $2,500 per tank (per Navy Environmental Requirements Guidebook).**

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(7) Control leakage through defective internal heating coils by monitoring the steam return and exhaust lines for contamination from internal heating coils that discharge into an open watercourse, or pass the steam return or exhaust lines through a settling tank, skimmer, or other separation or retention system.

♦ § 112.8(c)(7) ~ Leakage; Internal Heating Coils ♦

§ 112.8(c)(7) requires internal heating coils be monitored, via the steam return and exhaust lines, to control potential leakage into an open watercourse.

Occasionally installations subject to cold temperatures have ASTs with internal heating elements that heat the product in order to lower the product's viscosity and improve its ability to flow. For these installations, specify in this section how the steam return and exhaust lines are monitored for contamination from the internal heating coils, or describe what alternate type of separation or retention system is in place instead.

Section 4.2.6 of the Spill Prevention Guidance Document (NFESC, 1998) discusses internal tank heating coils [http://enviro.nfesc.navy.mil/ps/spillprev].

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(8) Engineer or update each container installation in accordance with good engineering practice to avoid discharges. You must provide at least one of the following devices:

(i) High liquid level alarms with an audible or visual signal at a constantly attended operation or surveillance station. In smaller facilities an audible air vent may suffice.

(ii) High liquid level pump cutoff devices set to stop flow at a predetermined container content level.

(iii) Direct audible or code signal communication between the container gauger and the pumping station.

(iv) A fast response system for determining the liquid level of each bulk storage container such as digital computers, telepulse, or direct vision gauges. If you use this alternative, a person must be present to monitor gauges and the overall filling of bulk storage containers.

(v) You must regularly test liquid level sensing devices to ensure proper operation.

♦ § 112.8(c)(8) ~ Good Engineering Practice – Alarm Systems ♦

§ 112.8(c)(8) requires each container installation to be engineered or updated with one of the following liquid level sensing devices:

- **High liquid level alarms with an audible or visual signal.**
- **High liquid level pump cutoff devices to stop flow at a predetermined level.**
- **Direct audible or code signal communication between the container gauger and the pumping station.**
- **A fast response system for determining liquid level, such as digital computers, telepulse, or direct vision gauges.**

Good engineering judgement should be used when selecting overfill protection devices. For instance, a 20,000 gal tank at a fuel farm or airfield should employ some type of a visual or audible high liquid level alarm and/or cutoff device, whereas a sight glass on a 100 gal arresting gear tank may be sufficient. Per EPA policy, 55 gal drums with secondary containment (e.g., placed on spill containment pallets) that are visible from all sides to allow periodic inspections do not necessarily require alarm systems, since the liquid level can typically be checked easily and regularly during filling operations. However, a clear explanation of why alarm systems are not practical, and how 'equivalent environmental protection' is provided (e.g., monthly inspections, storage on containment pallets, use of DOT-certified drums, strong contingency plan, etc.) must still be included in the SPCC Plan [*§ 112.7(a)(2)*].

Although § 112.8(c)(8) requires liquid level sensing devices be engineered or updated

at "each container installation", this section falls under the general heading of § 112.8(c), Bulk Storage Containers. Therefore, it would not be appropriate to apply these overfill protection requirements to electrical or other operating equipment, even through they may be considered container installations.

The overfill protection techniques employed at container installations may be addressed in the Plan by one of several approaches:

- **Include 'site-specific' or 'tank-specific' sections later in the Plan where these details can be adequately addressed individually. Clearly indicate / reference in this section exactly where these details can be found in the Plan.**
- **List the pertinent details of relevant sites or tanks collectively within this section. Tables or matrices addressing the required details could be created to clearly identify the attributes of each oil storage location.**
- **Develop a combination of the above two bullets by both presenting information collectively in this section (e.g., in the form of tables or matrices), as well as referencing individual site-specific or tank-specific sections. The benefit of the combination approach is that a collective summary of installation information, often sought by regulators or external users of SPCC Plan information, is readily available, in addition to individual detailed oil storage information, often more useful to installation personnel.**

Note that there may be defensible reasons (e.g., spatial limitations, safety concerns, costs or economic impacts) why a facility may deviate from the overfill protection system requirement. In such instances, a clear explanation of why such a device is not practicable must be provided in the Plan. The reason for nonconformance must be justified, and alternate methods of 'equivalent environmental protection' must be provided (refer to § 112.7(a)(2)).

Refer to the following industry standards for further guidance on alarm systems, discharge prevention systems, and inventory control: Chapters 2 and 5 of NFPA 30, "Flammable and Combustible Liquids Code" and API Recommended Practice 2350, "Overfill Protection for Storage Tanks in Petroleum Facilities".

Sections 4.2.7 and 4.2.8 of the Spill Prevention Guidance Document (NFESC, 1998) discuss various level controls and automatic controls, respectively [http://enviro.nfesc.navy.mil/ps/spillprev].

Refer also to the following sections of the Spill Prevention Resource Guide [NFESC, 2003] in Section 3 Tab B: Level Sensing; Overfill Prevention; Leak Detection (Double-Walled ASTs); Loading Rack Devices (for Spill Prevention).

<u>Cost Information</u>
Information on alarm systems and liquid level sensing devices is included in Section 4 Appendix A. Items discussed include:

- **Automatic tank gauging systems: centrally funded by DESC for facilities storing DESC product (per Naval Petroleum Office).**
- **Liquid level sensing device testing and maintenance: $200 - $1,000 per device (per Navy Environmental Requirements Guidebook).**
- **Level sensors with audible and/or visual overfill alarms: $7,500 - $10,000 plus $5,000 for installation for a typical complete fuel monitoring system utilizing magnetorestrictive technology for two tanks, or as low as $2,000 - $3,000 plus installation for basic, less automated magnetorestrictive systems (per vendor).**

(9) Observe effluent treatment facilities frequently enough to detect possible system upsets that could cause a discharge as described in § 112.1(b).

♦ § 112.8(c)(9) ~ Effluent Disposal Facilities ♦

§ 112.8(c)(9) requires effluent treatment facilities be observed frequently enough to detect any discharges.

Describe in this section how effluent treatment facilities, such as installation wastewater treatment plants, oil/water separators, and grease traps, are monitored and by whom.

Section 8.4 of the Spill Prevention Guidance Document (NFESC, 1998) contains discussion and provides guidance on treatment units including oil water separators, API separators, plate separators, three-chamber gasoline interceptors, and other treatment units [http://enviro.nfesc.navy.mil/ps/spillprev].

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(10) Promptly correct visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts. You must promptly remove any accumulations of oil in diked areas.

♦ § 112.8(c)(10) ~ Visible Oil Leaks ♦

§ 112.8(c)(10) requires visible discharges resulting in a loss of oil from the container or appurtenances to be promptly corrected, and any oil accumulated in diked areas to be removed.

Describe in this section how visible discharges from tanks are corrected at the installation when they are discovered.

The EPA initially proposed a 72-hour cleanup standard for removal of accumulations of oil, but ultimately decided that accumulation must be 'promptly' removed. Prompt removal means beginning the cleanup of any accumulation of oil immediately after discovery of the discharge. Beginning the cleanup of accumulated oil several days after discovery would not reasonably satisfy the intent of this requirement. [The 72-hour standard has been included here only to provide a frame of reference; there is no actual time interval defined or implied in § 112.8(c)(10).]

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(11) Position or locate mobile or portable oil storage containers to prevent a discharge as described in § 112.1(b). You must furnish a secondary means of containment, such as a dike or catchment basin, sufficient to contain the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation.

♦ § 112.8(c)(11) ~ Mobile Containers ♦

§ 112.8(c)(11) requires mobile or portable storage containers to be positioned to prevent a discharge to navigable waters. Secondary containment sufficient to capture the largest single compartment plus precipitation must be provided. Note that costs or economic impacts are not considered acceptable reasons for an installation to deviate

from this secondary containment requirement by utilizing the deviation rule of § 112.7(a)(2).

Describe in this section how secondary containment for mobile or portable storage containers, such as drums or tank trucks, is provided where these containers are routinely positioned. Examples of secondary containment for mobile or portable storage containers may include portable (i.e., collapsible) containment berms for vehicles or equipment; drum containment pallets; oil / water separators for high traffic areas; sumps or containment ditches; drain covers; or curbs or rollover (drive over) berms.

Temporary storage tanks that are positioned at construction sites, remediation sites, temporary contractor locations, etc., whether considered 'mobile' or otherwise, may need to be addressed in an SPCC Plan. Containers that are 55 gal or greater can be incorporated into either the larger [installation] SPCC Plan or into their own facility SPCC Plan if the 1,320 gal cumulative facility oil storage threshold is exceeded. Typically, facilities whose cumulative oil storage capacity of containers 55 gal or greater is less than 1,320 do not have to prepare an SPCC Plan. As noted earlier, the PE ultimately must decide upon the extent of the facility (refer to the section following § 112.2 for guidance on proper facility definition).

Sections 4.3 and 5.13 and 7 of the Spill Prevention Guidance Document (NFESC, 1998) discuss container storage, tank car and tank truck loading/unloading racks, and secondary containment, respectively [http://enviro.nfesc.navy.mil/ps/spillprev].

<u>Cost Information</u>
Information on numerous approaches to secondary containment for mobile containers and related items is included in Section 4 Appendix A. Relevant approaches and items discussed under mobile storage containment include:

- **Portable containment berms: $200 - $1,400 for smaller berms, $3,000 - $7,000 for larger berms (per vendors).**
- **Drum containment pallets and pallet inserts: $150 - $600 for pallets accommodating 2 - 4 drums, $450 - $600 for pallet inserts containing 55 - 80 gal (per vendors).**
- **Spill kits: $100 - $1,000 per kit (per vendors).**
- **Drain covers: $100 - $500 per cover (per vendors).**
- **Rollover (driveable) berm design for loading/unloading areas: $3,775 - $11,713 for tank capacities of 1,000 - 5,000 gal (per PWD).**
- **Doorway spill barriers: $2,985 - $10,909 for manual or automatic barriers from 3' - 10' wide (per vendors).**
- **Oil-swellable absorbent polymer storm drain inserts: $800 - $10,000 for drain protection shut-off systems or $81 - $227 for Imbiber Bead packets, pillows, blankets, boom, etc. (per vendors).**

(d) *Facility transfer operations, pumping, and facility process*

(1) Provide buried piping that is installed or replaced on or after August 16, 2002, with a protective wrapping and coating. You must also cathodically protect such buried piping installations or otherwise satisfy the corrosion protection standards for piping in part 280 of this chapter or a State program approved under part 281 of this chapter. If a section of buried line is exposed for any reason, you must carefully inspect it for deterioration. If you find corrosion damage, you must undertake additional examination and corrective action as

indicated by the magnitude of the damage.

♦ § 112.8(d)(1) ~ Buried Piping – Facility Transfer Operations, Pumping, and Facility Process (Onshore) (Excluding Production Facilities) ♦

§ 112.8(d)(1) requires new underground [metallic] piping have protective wrapping and coating, and be protected from corrosion.

Identify in this section what protective measures are in place for buried metallic piping at the installation. Note which piping at the installation is 'new' (i.e., installed on or after 16 August 2002).

Cathodic protection must be provided for buried metallic piping installed on or after 16 August 2002, as well as for other buried metallic piping installed after 1973 (when the initial SPCC regulations were promulgated) if soil conditions warrant. However, § 112.8(d)(1) does not require, and it would likely be impracticable, that piping systems installed between 1973 and August 16, 2002 be excavated solely for the purposes of retrofitting with cathodic protection. Note also that the EPA believes all soil conditions warrant protection of new and replaced buried piping; a deviation which seeks to avoid coating or cathodic protection, or some alternate means of buried piping protection, on the grounds that the soil is somehow incompatible with such measures, will not be acceptable to the EPA.

Refer to the following industry standards for further guidance on corrosion protection for buried piping: NACE Recommended Practice 0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" and STI Recommended Practice 892, "Recommended Practice for Corrosion Protection of Underground Piping Networks Associated with Liquid Storage and Dispensing Systems".

Section 5.3 of the Spill Prevention Guidance Document (NFESC, 1998) contains discussion and provides guidance on pipeline corrosion protection including protective coating systems, cathodic protection, and corrosion protection testing and inspection. Section 4.2.4 provides additional information on corrosion protection [http://enviro.nfesc.navy.mil/ps/spillprev].

<u>Cost Information</u>
Information on the protection of buried piping is included in Section 4 Appendix A. Measures discussed include:

- **Buried piping upgrade or replacement: $200 per foot for removal and replacement of substandard piping 10 feet or less in length, or $150 per foot for piping in excess of 20 feet in length, plus another 10% - 20% in design costs (per Navy Environmental Requirements Guidebook).**
- **Cathodic protection of buried pipelines: $1,500 - $2,500 per year per pipeline for impressed current systems, or $300 - $800 per year per pipeline for magnesium anode systems (per Navy Environmental Requirements Guidebook).**
- **Pipe wrapping or coating: $20 - $75 for 30 yards of pipe tape 1" to 4" in width (per vendors); $300 for primer coating, and $1,340 for pipe tape to coat and wrap 200 feet of 6" pipe (per NFESC).**

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(2) Cap or blank-flange the terminal connection at the transfer point and mark it as to origin when piping is not in service or is in standby service for an extended time.

♦ § 112.8(d)(2) ~ Terminal Connections ♦

§ 112.8(d)(2) requires the terminal connection to be capped shut at the transfer point when piping is out of service or in standby service for an extended period of time.

A practical (i.e., suggested) definition of a terminal connection is the connection point where the piping system of a tank farm or bulk storage facility is connected to the equipment (e.g., tank truck, tank car, vessel) delivering or receiving the oil product.

Describe in this section any piping that has been capped at the transfer point and has not been in service for an extended period of time (six months or longer). Capping pipelines that are out of service or in standby service for an extended period of time prevents releases due to operator error or vandalism.

(3) Properly design pipe supports to minimize abrasion and corrosion and allow for expansion and contraction.

♦ § 112.8(d)(3) ~ Pipe Supports ♦

§ 112.8(d)(3) requires pipe supports be designed to minimize abrasion and corrosion and allow for expansion and contraction.

Describe in this section how piping support design meets these requirements. For example, piping may be bracketed to walls or structures rather than rigidly attached; have roller or hanging supports; have loops, bends, or expansion joints; or be wrapped at joints or fastenings, to minimize abrasion.

Refer to the following industry standards for further guidance on minimizing abrasion and allowing for contraction and expansion: Chapter 2 of ASME 31.3, "Process Piping" and Section 8 of API Standard 2610, "Design, Construction, Operation, Maintenance, and Inspection of Terminal and Tank Facilities".

Section 5.2 of the Spill Prevention Guidance Document (NFESC, 1998) contains discussion and provides guidance on pipeline structural stability including support integrity, support spacing, and pipeline expansion and contraction [http://enviro.nfesc.navy.mil/ps/spillprev].

<u>Cost Information</u>
Information on the protection of buried piping is included in Section 4 Appendix A. Measures discussed include:

- **Pipe hangers and supports: up to $100 for clevis hangers, rolls, split rings, straps, or U-bolts, or up to $228 for saddles, for 1" - 12" pipe (per RS Means).**

(4) Regularly inspect all aboveground valves, piping, and appurtenances. During the inspection you must assess the general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. You must also conduct integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement.

♦ § 112.8(d)(4) ~ Inspection of Aboveground Valves and Piping ♦

§ 112.8(d)(4) requires aboveground pipes, valves, and appurtenances be regularly inspected. Integrity and leak testing of underground piping must also be performed when installed, modified, or replaced.

Describe in this section the inspection of aboveground piping, and the integrity and leak testing of underground piping accomplished during installation, modification, construction, relocation, or replacement.

Refer to Section § 112.7(d) for discussion of the general requirement for integrity testing valves and piping where secondary containment is not provided.

Refer to the following industry standards for further guidance on inspection and testing of valves, piping, and appurtenances: API 570, "Piping Inspection Code – Inspection, Repair, Alteration, and Rerating of In-service Piping Systems"; API Recommended Practice 574, "Inspection Practices for Piping System Components"; Section 3 of API Recommended Practice 1110, "Pressure Testing of Liquid Petroleum Pipelines"; and Chapter 4 of ASME B31.3, "Process Piping".

Section 5.4 of the Spill Prevention Guidance Document (NFESC, 1998) discusses piping system testing, and Section 10.5.3 discusses visual inspections for pipes, valves, fittings, pumps, and hoses. Section 4.2.12 discusses leak detection and monitoring [http://enviro.nfesc.navy.mil/ps/spillprev].

(5) Warn all vehicles entering the facility to be sure that no vehicle will endanger aboveground piping or other oil transfer operations.

♦ § 112.8(d)(5) ~ Vehicular Traffic ♦

§ 112.8(d)(5) requires vehicles entering the facility be warned not to endanger aboveground piping or other oil transfer operations.

Describe in this section how vehicles are warned of aboveground piping or other oil transfer operations when entering the installation. Vehicular warnings may include verbal warnings, signs, markings, or temporary protection of piping and equipment. Visual or physical barriers such as traffic bollards or fencing can also be employed to effectively warn vehicles.

Section 5.10 of the Spill Prevention Guidance Document (NFESC, 1998) discusses traffic collision protection [http://enviro.nfesc.navy.mil/ps/spillprev].

Refer also to the following section of the Spill Prevention Resource Guide [NFESC, 2003] in Section 3 Tab B: Gas Station Devices (for Damage Mitigation).

<u>Cost Information</u>
Information on approaches to warning vehicles of aboveground piping and other oil transfer operations is included in Section 4 Appendix A. Measures discussed include:

- **Signs and placards: up to $150 per sign (per PWD).**
- **Traffic bollards: $500 per steel concrete-filled bollard (per PWD).**

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§ 112.9 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil production facilities.

If you are the owner or operator of an onshore production facility, you must:

(a) Meet the general requirements for the Plan listed under § 112.7, and the specific discharge prevention and containment procedures listed under this section.

(b) *Oil production facility drainage.*

(1) At tank batteries and separation and treating areas where there is a reasonable possibility of a discharge as described in § 112.1(b), close and seal at all times drains of dikes or drains of equivalent measures required under § 112.7(c)(1), except when draining uncontaminated rainwater. Prior to drainage, you must inspect the diked area and take action as provided in § 112.8(c)(3)(ii), (iii), and (iv). You must remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods.

(2) Inspect at regularly scheduled intervals field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers, for an accumulation of oil that may have resulted from any small discharge. You must promptly remove any accumulations of oil.

(c) *Oil production facility bulk storage containers*

(1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and the conditions of storage.

(2) Provide all tank battery, separation, and treating facility installations with a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must safely confine drainage from undiked areas in a catchment basin or holding pond.

(3) Periodically and upon a regular schedule visually inspect each container of oil for deterioration and maintenance needs, including the foundation and support of each container that is on or above the surface of the ground.

(4) Engineer or update new and old tank battery installations in accordance with good engineering practice to prevent discharges. You must provide at least one of the following:

(i) Container capacity adequate to assure that a container will not overfill if a pumper/gauger is delayed in making regularly scheduled rounds.

(ii) Overflow equalizing lines between containers so that a full container can overflow to an adjacent container.

(iii) Vacuum protection adequate to prevent container collapse during a pipeline run or other transfer of oil from the container.

(iv) High level sensors to generate and transmit an alarm signal to the computer where the facility is subject to a computer production control system.

(d) *Facility transfer operations, oil production facility*

(1) Periodically and upon a regular schedule inspect all aboveground valves and piping associated with transfer operations for the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items.

(2) Inspect saltwater (oil field brine) disposal facilities often, particularly following a sudden change in atmospheric temperature, to detect possible system upsets capable of causing a discharge.

(3) Have a program of flowline maintenance to prevent discharges from each flowline.

♦ § 112.9 ~ Spill Prevention, Control, and Countermeasure Plan Requirements for Onshore Oil Production Facilities ♦

§ 112.9 does not typically apply to Navy or Marine Corps installations, since they are not onshore oil production facilities.

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§ 112.10 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil drilling and workover facilities.

If you are the owner or operator of an onshore oil drilling and workover facility, you must:

(a) Meet the general requirements listed under § 112.7, and also meet the specific discharge prevention and containment procedures listed under this section.

(b) Position or locate mobile drilling or workover equipment so as to prevent a discharge as described in § 112.1(b).

(c) Provide catchment basins or diversion structures to intercept and contain discharges of fuel, crude oil, or oily drilling fluids.

(d) Install a blowout prevention (BOP) assembly and well control system before drilling below any casing string or during workover operations. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while that BOP assembly and well control system are on the well.

♦ § 112.10 ~ Spill Prevention, Control, and Countermeasure Plan Requirements for Onshore Oil Drilling and Workover Facilities ♦

§ 112.10 does not typically apply to Navy or Marine Corps installations, since they are not onshore oil drilling and workover facilities.

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§ 112.11 Spill Prevention, Control, and Countermeasure Plan requirements for offshore oil drilling, production, or workover facilities.

If you are the owner or operator of an offshore oil drilling, production, or workover facility, you must:

(a) Meet the general requirements listed under § 112.7, and also meet the specific discharge prevention and containment procedures listed under this section.

(b) Use oil drainage collection equipment to prevent and control small oil discharges around pumps, glands, valves, flanges, expansion joints, hoses, drain lines, separators, treaters, tanks, and associated equipment. You must control and direct facility drains toward a central collection sump to prevent the facility from having a discharge as described in § 112.1(b). Where drains and sumps are not practicable, you must remove oil contained in collection equipment as often as necessary to prevent overflow.

(c) For facilities employing a sump system, provide adequately sized sump and drains and make available a spare pump to remove liquid from the sump and assure that oil does not escape. You must employ a regularly scheduled preventive maintenance inspection and testing program to assure reliable operation of the liquid removal system and pump start-up device. Redundant automatic sump pumps and control devices may be required on some installations.

(d) At facilities with areas where separators and treaters are equipped with dump valves which predominantly fail in the closed position and where pollution risk is high, specially equip the facility to prevent the discharge of oil. You must prevent the discharge of oil by:

(1) Extending the flare line to a diked area if the separator is near shore;

(2) Equipping the separator with a high liquid level sensor that will automatically shut in wells producing to the separator; or

(3) Installing parallel redundant dump valves.

(e) Equip atmospheric storage or surge containers with high liquid level sensing devices that activate an alarm or control the flow, or otherwise prevent discharges.

(f) Equip pressure containers with high and low pressure sensing devices that activate an alarm or control the flow.

(g) Equip containers with suitable corrosion protection.

(h) Prepare and maintain at the facility a written procedure within the Plan for inspecting and testing pollution prevention equipment and systems.

(i) Conduct testing and inspection of the pollution prevention equipment and systems at the facility on a scheduled periodic basis, commensurate with the complexity, conditions, and circumstances of the facility and any other appropriate regulations. You must use simulated discharges for testing and inspecting human and equipment pollution control and countermeasure systems.

(j) Describe in detailed records surface and subsurface well shut-in valves and devices in use at the facility for each well sufficiently to determine their method of activation or control, such as pressure differential, change in fluid or flow conditions, combination of pressure and flow, manual or remote control mechanisms.

(k) Install a BOP assembly and well control system during workover operations and before drilling below any casing string. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while the BOP assembly and well control system are on the well.

(l) Equip all manifolds (headers) with check valves on individual flowlines.

(m) Equip the flowline with a high pressure sensing device and shut-in valve at the wellhead if the shut-in well pressure is greater than the working pressure of the flowline and manifold valves up to and including the header valves. Alternatively you may provide a pressure relief system for flowlines.

(n) Protect all piping appurtenant to the facility from corrosion, such as with protective coatings or cathodic protection.

(o) Adequately protect sub-marine piping appurtenant to the facility against environmental stresses and other activities such as fishing operations.

(p) Maintain sub-marine piping appurtenant to the facility in good operating condition at all times. You must periodically and according to a schedule inspect or test such piping for failures. You must document and keep a record of such inspections or tests at the facility.

♦ § 112.11 ~ Spill Prevention, Control, and Countermeasure Plan Requirements for Offshore Oil Drilling, Production, or Workover Facilities ♦

§ 112.11 does not typically apply to Navy or Marine Corps installations, since they are not offshore oil drilling, production, or workover facilities.

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4. Part 112 is amended by adding subpart C consisting of §§ 112.12 through 112.15 to read as follows:

Subpart C – Requirements for Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and for Vegetable Oils, Including Oils from Seeds, Nuts, Fruits and Kernels

Sec.
112.12 Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities).
112.13 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil production facilities.
112.14 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil drilling and workover facilities.
112.15 Spill Prevention, Control, and Countermeasure Plan requirements for offshore oil drilling, production, or workover facilities.

Subpart C – Requirements for Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and for Vegetable Oils, including Oils from Seeds, Nuts, Fruits, and Kernels.

§ 112.12 Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities)

If you are the owner or operator of an onshore facility (excluding a production facility), you must:

(a) Meet the general requirements for the Plan listed under § 112.7, and the specific discharge prevention and containment procedures listed in this section.

(b) *Facility drainage*

(1) Restrain drainage from diked storage areas by valves to prevent a discharge into the drainage system or facility effluent treatment system, except where facility systems are designed to control such discharge. You may empty diked areas by pumps or ejectors; however, you must manually activate these pumps or ejectors and must inspect the condition of the accumulation before starting, to ensure no oil will be discharged.

(2) Use valves of manual, open-and-closed design, for the drainage of diked areas. You may not use flapper-type drain valves to drain diked areas. If your facility drainage drains directly into a watercourse and not into an on-site wastewater treatment plant, you must inspect and may drain uncontaminated retained stormwater, subject to the requirements of paragraphs

(c)(3)(ii), (iii), and (iv) of this section.

(3) Design facility drainage systems from undiked areas with a potential for a discharge (such as where piping is located outside containment walls or where tank truck discharges may occur outside the loading area) to flow into ponds, lagoons, or catchment basins designed to retain oil or return it to the facility. You must not locate catchment basins in areas subject to periodic flooding.

(4) If facility drainage is not engineered as in paragraph (b)(3) of this section, equip the final discharge of all ditches inside the facility with a diversion system that would, in the event of an uncontrolled discharge, retain oil in the facility.

(5) Where drainage waters are treated in more than one treatment unit and such treatment is continuous, and pump transfer is needed, provide two "lift" pumps and permanently install at least one of the pumps. Whatever techniques you use, you must engineer facility drainage systems to prevent a discharge as described in § 112.1(b) in case there is an equipment failure or human error at the facility.

(c) *Bulk storage containers*

(1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature.

(2) Construct all bulk storage container installations so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must ensure that diked areas are sufficiently impervious to contain discharged oil. Dikes, containment curbs, and pits are commonly employed for this purpose. You may also use an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a facility catchment basin or holding pond.

(3) Not allow drainage of uncontaminated rainwater from the diked area into a storm drain or discharge of an effluent into an open watercourse, lake, or pond, bypassing the facility treatment system unless you:

(i) Normally keep the bypass valve sealed closed.

(ii) Inspect the retained rainwater to ensure that its presence will not cause a discharge as described in § 112.1(b).

(iii) Open the bypass valve and reseal it following drainage under responsible supervision; and

(iv) Keep adequate records of such events, for example, any records required under permits issued in accordance with §§ 122.41(j)(2) and 122.41(m)(3) of this chapter.

(4) Protect any completely buried metallic storage tank installed on or after January 10, 1974 from corrosion by coatings or cathodic protection compatible with local soil conditions. You must regularly leak test such completely buried metallic storage tanks.

(5) Not use partially buried or bunkered metallic tanks for the storage of oil, unless you protect the buried section of the tank from corrosion. You must protect partially buried and bunkered tanks from corrosion by coatings or cathodic protection compatible with local soil conditions.

(6) Test each aboveground container for integrity on a regular schedule, and whenever you make material repairs. The frequency of and type of testing must take into account container size

and design (such as floating roof, skid-mounted, elevated, or partially buried). You must combine visual inspection with another testing technique such as hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or another system of non-destructive shell testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of inspections and tests kept under usual and customary business practices will suffice for purposes of this paragraph.

(7) Control leakage through defective internal heating coils by monitoring the steam return and exhaust lines for contamination from internal heating coils that discharge into an open watercourse, or pass the steam return or exhaust lines through a settling tank, skimmer, or other separation or retention system.

(8) Engineer or update each container installation in accordance with good engineering practice to avoid discharges. You must provide at least one of the following devices:

(i) High liquid level alarms with an audible or visual signal at a constantly attended operation or surveillance station. In smaller facilities an audible air vent may suffice.

(ii) High liquid level pump cutoff devices set to stop flow at a predetermined container content level.

(iii) Direct audible or code signal communication between the container gauger and the pumping station.

(iv) A fast response system for determining the liquid level of each bulk storage container such as digital computers, telepulse, or direct vision gauges. If you use this alternative, a person must be present to monitor gauges and the overall filling of bulk storage containers.

(v) You must regularly test liquid level sensing devices to ensure proper operation.

(9) Observe effluent treatment facilities frequently enough to detect possible system upsets that could cause a discharge as described in § 112.1(b).

(10) Promptly correct visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts. You must promptly remove any accumulations of oil in diked areas.

(11) Position or locate mobile or portable oil storage containers to prevent a discharge as described in § 112.1(b). You must furnish a secondary means of containment, such as a dike or catchment basin, sufficient to contain the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation.

(d) *Facility transfer operations, pumping, and facility process*

(1) Provide buried piping that is installed or replaced on or after August 16, 2002, with a protective wrapping and coating. You must also cathodically protect such buried piping installations or otherwise satisfy the corrosion protection standards for piping in part 280 of this chapter or a State program approved under part 281 of this chapter. If a section of buried line is exposed for any reason, you must carefully inspect it for deterioration. If you find corrosion damage, you must undertake additional examination and corrective action as indicated by the magnitude of the damage.

(2) Cap or blank-flange the terminal connection at the transfer point and mark it as to origin when

piping is not in service or is in standby service for an extended time.

(3) Properly design pipe supports to minimize abrasion and corrosion and allow for expansion and contraction.

(4) Regularly inspect all aboveground valves, piping, and appurtenances. During the inspection you must assess the general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. You must also conduct integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement.

(5) Warn all vehicles entering the facility to be sure that no vehicle will endanger aboveground piping or other oil transfer operations.

♦ § 112.12 ~ Spill Prevention, Control, and Countermeasure Plan Requirements for Onshore Facilities (Excluding Production Facilities) ♦

§ 112.12 contains the exact same (i.e., verbatim) requirements as § 112.8, but regulates animal and vegetable oil storage rather than petroleum oil storage.

Many Navy and Marine Corps installations maintain tanks or containers that store animal oil (including fats and greases) or vegetable oil. Animal and vegetable oil containers at the facility that are 55 gal or greater must be included in the SPCC Plan, just as similar sized petroleum oil containers are. Correspondingly, these animal and vegetable oil containers must adhere to the same drainage, secondary containment, testing, inspection, and all other requirements the petroleum oil tanks are subject to.

However, as discussed in the guidance section following § 112.2, it is possible for an installation to define a segment of the installation as a separate facility that is not subject to Part 112, and therefore does not require its own separate SPCC Plan. For example, the animal or vegetable oil containers or grease traps belonging to a messing facility (e.g., a lessee snack shop or fast-food restaurant) might reasonably be defined as a separate facility-- but any petroleum oil storage, such as an emergency generator day tank or heating oil tank, may also need to be included in the facility definition. If the cumulative quantity of oil storage in the container(s) (55 gal or greater) does not exceed 1,320 gal, the facility would not be subject to Part 112. Alternately, if the 1,320 gal threshold is exceeded, the tank(s) (55 gal or greater), including any animal and vegetable oil containers, must be included in an SPCC Plan developed for this facility (or simply be incorporated into the installation SPCC Plan).

The extent of the facility will vary according to the circumstances of the site. EPA guidance on the specific factors to be used in determining the extent of a facility include the ownership or operation of those buildings, structures, or pieces of equipment, or the type of activities being carried on at the facility. As noted earlier, the PE ultimately must decide upon the extent of the facility.

For further information, refer to guidance provided for the subsections of § 112.8 earlier in this document.

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§ 112.13 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil production facilities.

If you are the owner or operator of an onshore production facility, you must:

(a) Meet the general requirements for the Plan listed under § 112.7, and the specific discharge prevention and containment procedures listed under this section.

(b) *Oil production facility drainage*

(1) At tank batteries and separation and treating areas where there is a reasonable possibility of a discharge as described in § 112.1(b), close and seal at all times drains of dikes or drains of equivalent measures required under § 112.7(c)(1), except when draining uncontaminated rainwater. Prior to drainage, you must inspect the diked area and take action as provided in § 112.12(c)(3)(ii), (iii), and (iv). You must remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods.

(2) Inspect at regularly scheduled intervals field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers, for an accumulation of oil that may have resulted from any small discharge. You must promptly remove any accumulations of oil.

(c) *Oil production facility bulk storage containers.*

(1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and the conditions of storage.

(2) Provide all tank battery, separation, and treating facility installations with a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must safely confine drainage from undiked areas in a catchment basin or holding pond.

(3) Periodically and upon a regular schedule visually inspect each container of oil for deterioration and maintenance needs, including the foundation and support of each container that is on or above the surface of the ground.

(4) Engineer or update new and old tank battery installations in accordance with good engineering practice to prevent discharges. You must provide at least one of the following:

(i) Container capacity adequate to assure that a container will not overfill if a pumper/gauger is delayed in making regularly scheduled rounds.

(ii) Overflow equalizing lines between containers so that a full container can overflow to an adjacent container.

(iii) Vacuum protection adequate to prevent container collapse during a pipeline run or other transfer of oil from the container.

(iv) High level sensors to generate and transmit an alarm signal to the computer where the facility is subject to a computer production control system.

(d) *Facility transfer operations, oil production facility.*

(1) Periodically and upon a regular schedule inspect all aboveground valves and piping associated with transfer operations for the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items.

(2) Inspect saltwater (oil field brine) disposal facilities often, particularly following a sudden change in atmospheric temperature, to detect possible system upsets capable of causing a discharge.

(3) Have a program of flowline maintenance to prevent discharges from each flowline.

♦ § 112.13 ~ Spill Prevention, Control, and Countermeasure Plan Requirements for Onshore Oil Production Facilities ♦

§ 112.13 does not typically apply to Navy or Marine Corps installations, since they are not onshore oil production facilities.

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§ 112.14 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil drilling and workover facilities.

If you are the owner or operator of an onshore oil drilling and workover facility, you must:

(a) Meet the general requirements listed under § 112.7, and also meet the specific discharge prevention and containment procedures listed under this section.

(b) Position or locate mobile drilling or workover equipment so as to prevent a discharge as described in § 112.1(b).

(c) Provide catchment basins or diversion structures to intercept and contain discharges of fuel, crude oil, or oily drilling fluids.

(d) Install a blowout prevention (BOP) assembly and well control system before drilling below any casing string or during workover operations. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while that BOP assembly and well control system are on the well.

♦ § 112.14 ~ Spill Prevention, Control, and Countermeasure Plan Requirements for Onshore Oil Drilling and Workover Facilities ♦

§ 112.14 does not typically apply to Navy or Marine Corps installations, since they are not onshore oil drilling and workover facilities.

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§ 112.15 Spill Prevention, Control, and Countermeasure Plan requirements for offshore oil drilling, production, or workover facilities.

If you are the owner or operator of an offshore oil drilling, production, or workover facility, you must:

(a) Meet the general requirements listed under § 112.7, and also meet the specific discharge prevention and containment procedures listed under this section.

(b) Use oil drainage collection equipment to prevent and control small oil discharges around pumps, glands, valves, flanges, expansion joints, hoses, drain lines, separators, treaters, tanks, and associated equipment. You must control and direct facility drains toward a central collection sump to prevent the facility from having a discharge as described in § 112.1(b). Where drains and sumps are not practicable, you must remove oil contained in collection equipment as often as necessary to prevent overflow.

(c) For facilities employing a sump system, provide adequately sized sump and drains and make available a spare pump to remove liquid from the sump and assure that oil does not escape. You must employ a regularly scheduled preventive maintenance inspection and testing program to

assure reliable operation of the liquid removal system and pump start-up device. Redundant automatic sump pumps and control devices may be required on some installations.

(d) At facilities with areas where separators and treaters are equipped with dump valves which predominantly fail in the closed position and where pollution risk is high, specially equip the facility to prevent the discharge of oil. You must prevent the discharge of oil by:

(1) Extending the flare line to a diked area if the separator is near shore;

(2) Equipping the separator with a high liquid level sensor that will automatically shut in wells producing to the separator; or

(3) Installing parallel redundant dump valves.

(e) Equip atmospheric storage or surge containers with high liquid level sensing devices that activate an alarm or control the flow, or otherwise prevent discharges.

(f) Equip pressure containers with high and low pressure sensing devices that activate an alarm or control the flow.

(g) Equip containers with suitable corrosion protection.

(h) Prepare and maintain at the facility a written procedure within the Plan for inspecting and testing pollution prevention equipment and systems.

(i) Conduct testing and inspection of the pollution prevention equipment and systems at the facility on a scheduled periodic basis, commensurate with the complexity, conditions, and circumstances of the facility and any other appropriate regulations. You must use simulated discharges for testing and inspecting human and equipment pollution control and countermeasure systems.

(j) Describe in detailed records surface and subsurface well shut-in valves and devices in use at the facility for each well sufficiently to determine their method of activation or control, such as pressure differential, change in fluid or flow conditions, combination of pressure and flow, manual or remote control mechanisms.

(k) Install a BOP assembly and well control system during workover operations and before drilling below any casing string. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while that BOP assembly and well control system are on the well.

(l) Equip all manifolds (headers) with check valves on individual flowlines.

(m) Equip the flowline with a high pressure sensing device and shut-in valve at the wellhead if the shut-in well pressure is greater than the working pressure of the flowline and manifold valves up to and including the header valves. Alternatively you may provide a pressure relief system for flowlines.

(n) Protect all piping appurtenant to the facility from corrosion, such as with protective coatings or cathodic protection.

(o) Adequately protect sub-marine piping appurtenant to the facility against environmental stresses and other activities such as fishing operations.

(p) Maintain sub-marine piping appurtenant to the facility in good operating condition at all times. You must periodically and according to a schedule inspect or test such piping for failures. You must document and keep a record of such inspections or tests at the facility.

♦ § 112.15 ~ Spill Prevention, Control, and Countermeasure Plan Requirements for Offshore Oil Drilling, Production, or Workover Facilities ♦

§ 112.15 does not typically apply to Navy or Marine Corps installations, since they are not offshore oil drilling, production, or workover facilities.